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THE ROLE OF PETROLEUM AND NATURAL GAS FROM THE OUTER CONTINENTAL SHELF IN THE NATIONAL SUPPLY OF PETROLEUM AND NATURAL GAS

TECHNICAL BULLETIN 5

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
Washington, D.C. 20240

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INTRODUCTION

Under the Secretary of the Interior, the Bureau of Land Management is responsible for the leasing of all mineral rights on the Outer Continental Shelf—that portion of the Continental Shelf which lies beyond the jurisdiction of the individual States.

The Bureau of Land Management, aware that the production of petroleum and natural gas from the OCS will be a significant factor in satisfying the future energy requirements of the Nation, had two studies prepared under contract by Foster Associates, Inc., Washington, D.C. The studies appear in this book as Section I, Supply and Demand; and as Section II, The Cost of Finding and Proceding Hydrocarbon Supplies. Each is complete in itself.

Section I provides a quantitative estimate of the role which petroleum and natural gas from the OCS will play in meeting future national energy requirements. The study is preceded by a narrative summary of the results of the study, and is followed by nine conclusions emphasizing the more significant variables affecting the supply-demand outlook for petroleum and gas

At the end of the text are six appendices which provide statistical details of technical aspects referred to in the text, and a set of exhibits which are numbered consecutively by chapters as they are referenced in the text.

Section II provides an estimate of the cost and profitability of finding and producing hydrocarbon supplies, separately for offshore and onshore areas.

The study is preceded by a narrative summary of findings and conclusions. An appendix provides statistical details of technical aspects referred to in the text.

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ACKNOWLEDGEMENTS

SECTION I

SUPPLY AND DEMAND

This study was prepared by and under the direction of Radford L. Schantz. W. Gibson Jaworek contributed to all parts of the study, but especially to Chapter C. Principal staff analysts assisting in the preparation of the report were John Freitag, Thomas E. Browne, Sara Lepman, Louise Waldruff, and Ellen Brown. J. Rhoads Foster reviewed the report and made many helpful suggestions.

Foster Economic Consultants, Ltd., of Calgary, Alberta, Canada, prepared a special study on petroleum and natural gas supplies in Canada. Arthur D. Little, Inc., of Cambridge, Mass., prepared a special study of liquefied natural gas. Assistance was also provided by two independent consultants who are affiliated with Foster Associates: David N. McClanahan, Houston, Tex., assisted in all parts of the study, but especially with regard to natural gas liquids; Clarke B. Gillespie, Fort Worth, Tex., provided a special study on nuclear stimulation.

Acknowledgement is also given to a number of people in both government and industry who provided valuable assistance in data gathering and in the review of preliminary drafts of the report.

SECTION II

THE COST OF FINDING AND PRODUCING HYDROCARBON SUPPLIES

This study was written and directed by Dr. Stephen F. Sherwin with the assistance of Sara L. Lepman who prepared the statistical appendix. Clarke B. Gillespie provided the reservoir depletion curves and assisted in the collection of cost data for offshore operations. Mary J. Klipple performed the research on offshore transportation costs, and Evelynne Gordon assisted in the assembly of data on time lag. Dr. J. Rhoads Foster and Celia Star Gody provided many helpful suggestions in their review of the study.

Acknowledgement is also given to the cooperation of the Louisiana State Geological Survey; the Geological Survey, U.S. Department of the Interior; and the many offshore drilling operators in providing access to data.

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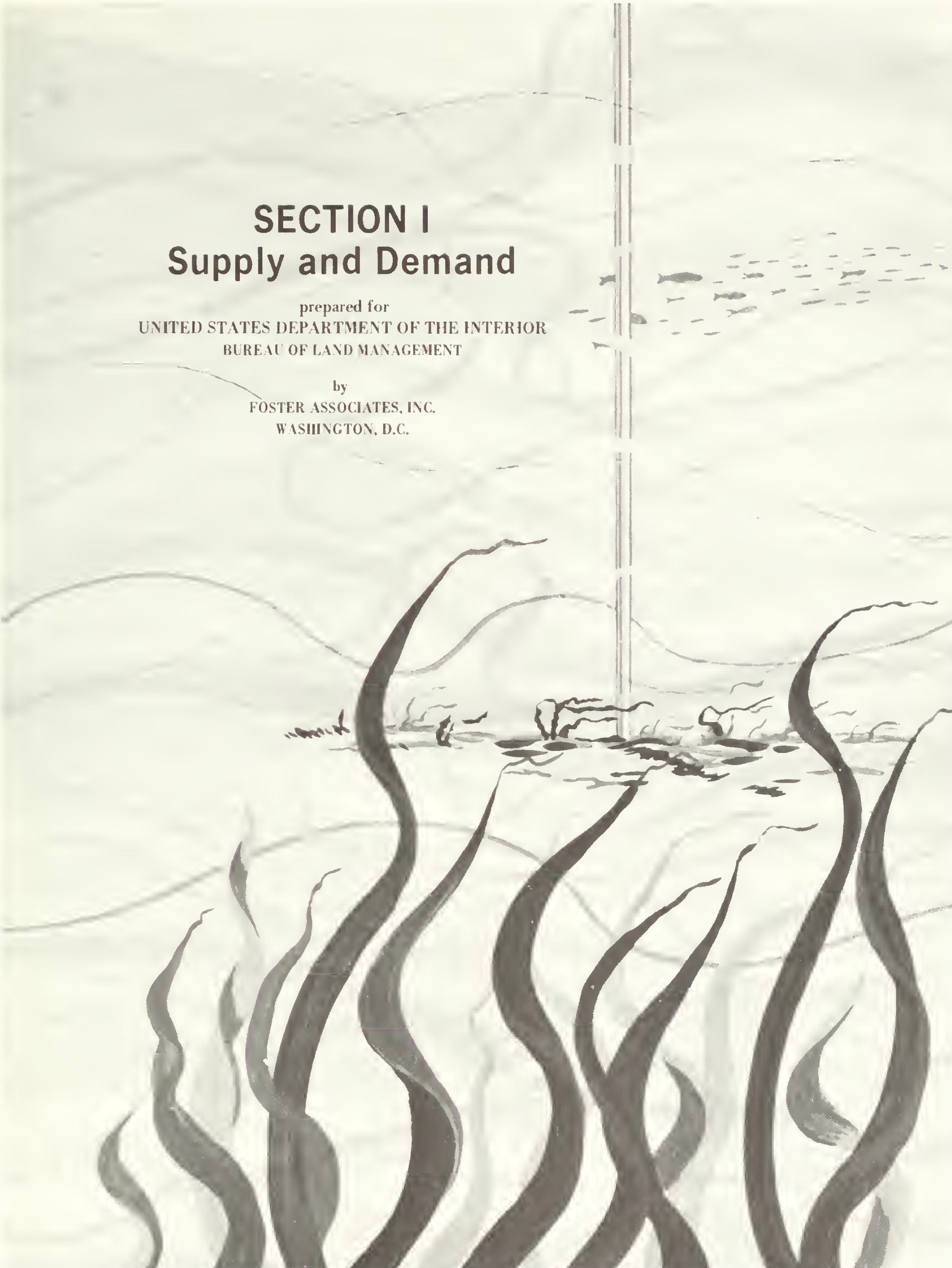
SECTION I
Supply and Demand

prepared for
UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

by
FOSTER ASSOCIATES, INC.
WASHINGTON, D.C.



SUMMARY

1. Natural Gas

Analysis of natural gas supply and demand trends indicates that indigenous supplies, supplemented by a relatively modest continuation of overland imports, should be sufficient to meet a strong gain in consumption until about 1975, *assuming* that there are adequate incentives to find and develop the requisite new reserves. Increasingly the Gulf of Mexico Outer Continental Shelf will be expected to provide a considerable portion of these new reserves to meet incremental increases in demand, not only to 1975, but also in subsequent years.

Between 1975 and 1985, with demand continuing to grow, new additional sources of natural gas will be required in order to maintain the national proved inventory of reserves at a reasonable minimum level. These alternative sources could include the Atlantic Outer Continental Shelf, if commercial reserves are established. It would therefore seem appropriate to commence now measures which will define the natural gas supply potential of the Atlantic Outer Continental Shelf.

While potential reserves in both the onshore and offshore areas of the United States seem to be sufficient to supply the bulk of projected natural gas consumption beyond the year 1985, supplementation from other sources may be desirable as a buffer. These additional sources could include gasification of domestic coal and overseas imports of liquefied natural gas. Of greatest importance, however, will be the need to define the natural gas supply potential in Alaska, both onshore and offshore, and to develop methods of transportation which will allow the supplies to be delivered to the "south forty-eight" at competitive prices.

2. Petroleum

The discovery of substantial reserves of petroleum on the North Slope of Alaska has opened up an entirely new major petroleum province for North America. The magnitude of this discovery suggests that the previous concern of an imminent deficiency of domestic petroleum supplies to meet anticipated requirements can be postponed for an indefinite period. As a result, there is no indicated need for petroleum supplies from oil shale, tar sands, the liquefaction of coal, or an increase in imports above the assumed level of 20 percent of demand to the year 1975.

Production of crude oil and natural gas liquids from the Gulf of Mexico Outer Continental Shelf is projected to increase at an impressive rate of growth through the year 1985, even after full consideration of the impact of a set of assumed significant levels of production from the North Slope of Alaska. Crude oil production from the Pacific Outer Continental Shelf is projected to expand considerably until 1975, with the outlook thereafter conditioned on developments on the North Slope. On the basis of these con-

SUMMARY OF LONG-TERM ENERGY CONSUMPTION PROJECTIONS

	1967	1975	1985	2000
PETROLEUM				
Quadrillion Btu	25.2	32.0	42.0	56.0
Thousand Barrels per Day	12,600	16,200	21,300	28,300
Annual Growth Rate (Percent)	–	3.2	2.8	1.9
NATURAL GAS				
Quadrillion Btu	18.4	25.5	34.5	42.0
Trillion Cubic Feet	17.8	24.6	33.3	40.6
Annual Growth Rate (Percent)	–	4.1	3.1	1.3
OTHER ENERGY RESOURCES				
Quadrillion Btu	15.3	22.0	37.0	74.0
Annual Growth Rate (Percent)	–	4.9	5.6	4.7
TOTAL ENERGY CONSUMPTION				
Quadrillion Btu	58.8	79.5	113.5	172.0
Annual Growth Rate (Percent)	–	3.9	3.6	2.8

clusions, it is indicated that the need for additional supplies of petroleum from unexplored Outer Continental Shelf areas will not be as pressing as indicated for new supplies of natural gas.

3. Conclusions

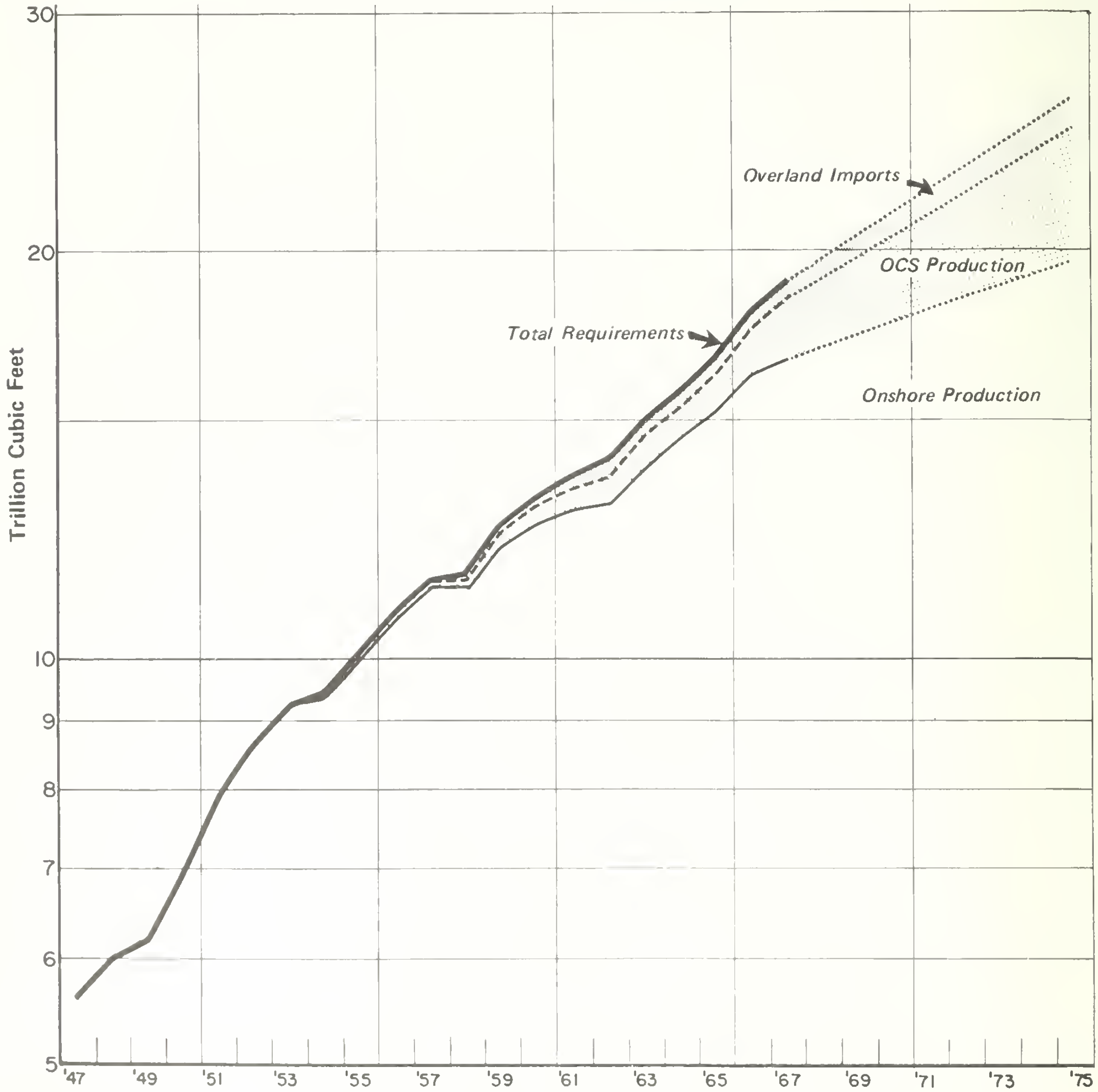
The following nine conclusions, with accompanying tabular and graphical illustrations, highlight the major influences bearing on the role of the Outer Continental Shelf in the future supply of petroleum and natural gas in the United States. These brief conclusions are conditioned on a number of assumptions and qualifications which underlie the analysis on which they are based as explained in the text of the report.

(a) **Projection of Energy Demand**

Assuming no "revolutionary" change in our energy technology, it is projected that the demand for energy in the United States will continue to expand by an average annual rate of 3.8 percent to 1975, slackening thereafter to 3.6 percent per year until 1985, and dropping to 2.8 percent per year by 2000.

It is anticipated that petroleum's share of the energy mix, although increasing in absolute terms, will gradually decline from 43 percent in 1967 to about 37 percent in 1985. On the other hand, the percentage contribution of natural gas is forecast to

ESTIMATED SOURCES OF NATURAL GAS
TO MEET PROJECTED REQUIREMENTS TO 1975



Excludes Alaska

remain fairly constant at 30 percent. Other energy resources, helped particularly by nuclear power, are expected to increase their share of energy demand from 26 percent in 1967 to 33 percent by 1985.

Extrapolation of these projections to the year 2000 indicates a further shifting of the overall energy mix in favor of other energy resources, primarily nuclear power. Consumption of natural gas is projected to drop to approximately 24 percent of total energy consumption, petroleum to 33 percent, and other energy resources to increase to 43 percent.

(b) Trend in Natural Gas Supply to 1975

All indications point to the conclusion that sufficient domestic supplies of natural gas, with a continued modest supplementation of overland imports, will be forthcoming to meet anticipated requirements to 1975. It is projected that over 95 percent of the natural gas requirements can be met from domestic onshore and OCS areas throughout this period.

To achieve this result, however, it will be necessary to provide additional economic incentives to allow a higher discovery level of new reserves than has been experienced in the recent past. Even under these conditions, the national reserve-production ratio is indicated to decline from 15.7 years in 1967 to about 12 years in 1975, exclusive of any reserves from Alaska.

While there remains some uncertainty as to when the reserve-production ratio will reach the vicinity of 12 years, this level is considered to be the minimum national inventory needed to maintain deliverability requirements.

(c) Projection of Natural Gas Supply, 1975 to 1985

During the decade 1975-1985, it will be necessary to further supplement domestic gas supplies in order to maintain a national reserve-production ratio of 12 years. In addition to a continuation of overland imports, this supplementation could come from liquefied natural gas imports or from gasification of domestic coal, if technology can reduce the cost of these supplies to competitive levels. Of considerable importance is the possibility of achieving this supplementation by (1) opening up new gas producing provinces in the Atlantic OCS, dependent upon these reserves being available in commercial quantities, and (2) transporting Alaskan gas to the U.S. mainland, assuming technology and other changes can be effected to reduce the delivered cost to competitive levels.

A probable breakdown of natural gas supply sources to meet U.S. requirements in 1975 and 1985 illustrates the future importance of OCS production:

(d) Natural Gas Supply Beyond 1985

Beyond 1985 increasing supplementation will be required if natural gas is to maintain its present viability as a major energy resource. While potential reserves in the United States seem to be sufficient to meet the larger part of domestic requirements, there remains the uncertainty as to whether or not the reserves can be translated into commercially proved supplies. These further important supplements could come from Alaska, including possibly the Alaska OCS, if transportation technology and cost reduction

PROBABLE SOURCES OF U.S. SUPPLY OF NATURAL GAS IN 1975 AND 1985
(Percent)

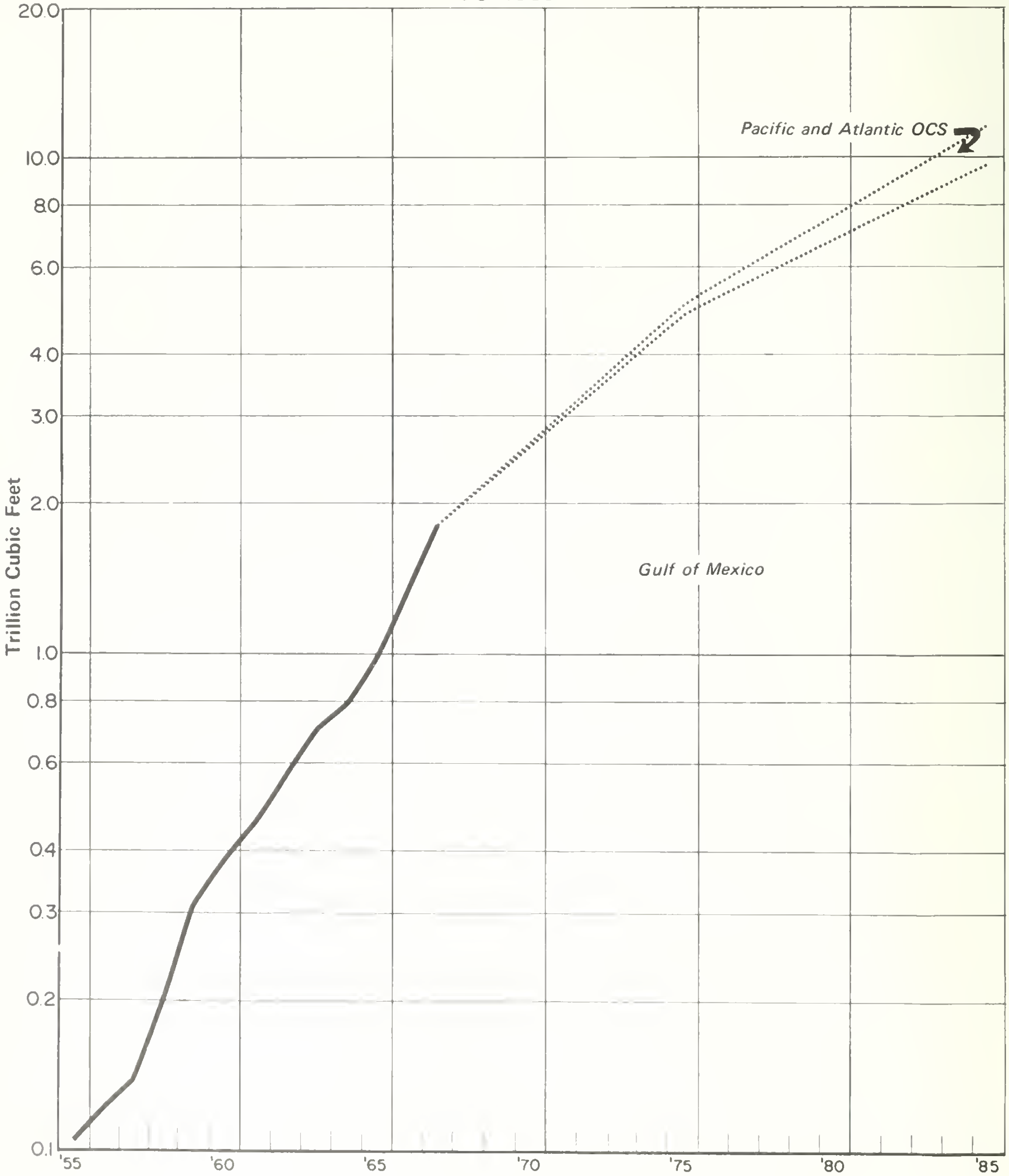
	1975	1985
Domestic onshore production, excluding Alaska	76.0	55.2
OCS production, excluding Alaska but including possible Atlantic OCS production by 1985	19.4	33.4
Canadian imports	4.6	5.7
Alaskan gas production and/or LNG imports and/or synthetic gas		5.7
TOTAL REQUIREMENTS	100.0	100.0

factors can be effected. Nuclear stimulation and deeper drilling represent potential ways of achieving new supplies onshore, as does drilling in deeper waters of OCS areas, especially in the Gulf of Mexico. Gasification of domestic coal reserves at selected sites, further imports of gas by pipeline and by tanker represent yet other possible alternatives. The period of serious deficiency in gas supplies could be postponed indefinitely if a combination of economic supply from among these alternatives can be successfully brought about.

(e) Projection of Natural Gas Production from the OCS

Production of natural gas from the Outer

PROJECTION OF NATURAL GAS PRODUCTION FROM THE OUTER CONTINENTAL SHELF TO 1985



Continental Shelf is projected to accelerate during the 1970's and continue to increase thereafter as reserve limitations begin to constrict the availability of onshore supplies. In volume, total OCS production was 1.8 trillion cubic feet in 1967; by 1975 it is expected to be about 5 trillion cubic feet; and by 1985 about 11.6 trillion cubic feet, at which time it will account for 38 percent of projected domestic gas production. This 1985 production is estimated to include about 9.6 trillion cubic feet from the Gulf of Mexico, about 0.5 trillion from the Pacific OCS, and an illustrative 1.5 trillion from a producing area which might be established in the Atlantic OCS.

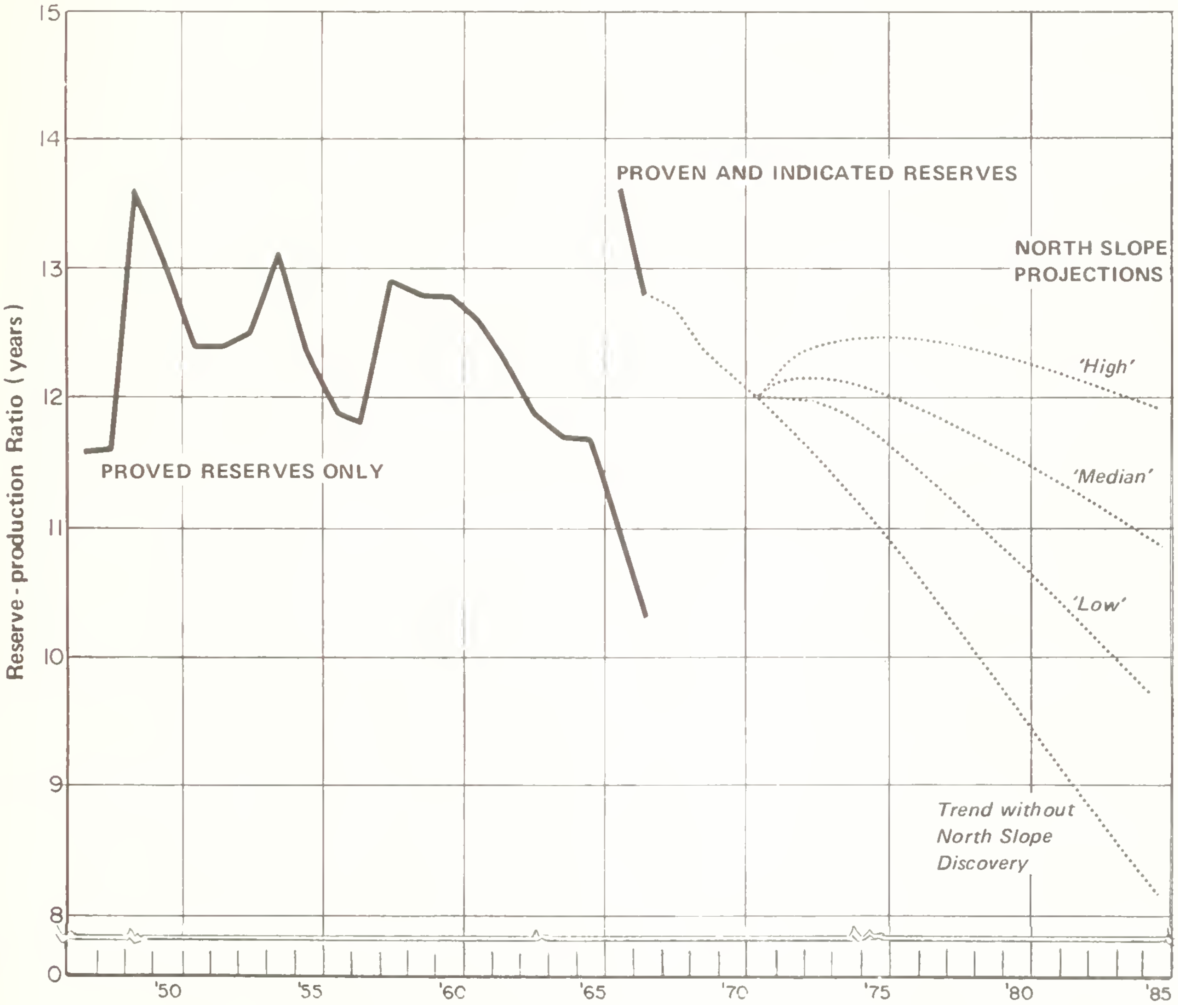
It is impossible to quantify the level of natural gas production from the OCS after 1985. Nevertheless, it must be concluded, because about 40 percent of the Nation's remaining economically recoverable natural gas reserves are estimated to be located in these areas, that an expanding dependence will be placed on the OCS toward the end of the century.

(f) Impact of The North Slope on U.S. Crude Oil Reserves to 1985

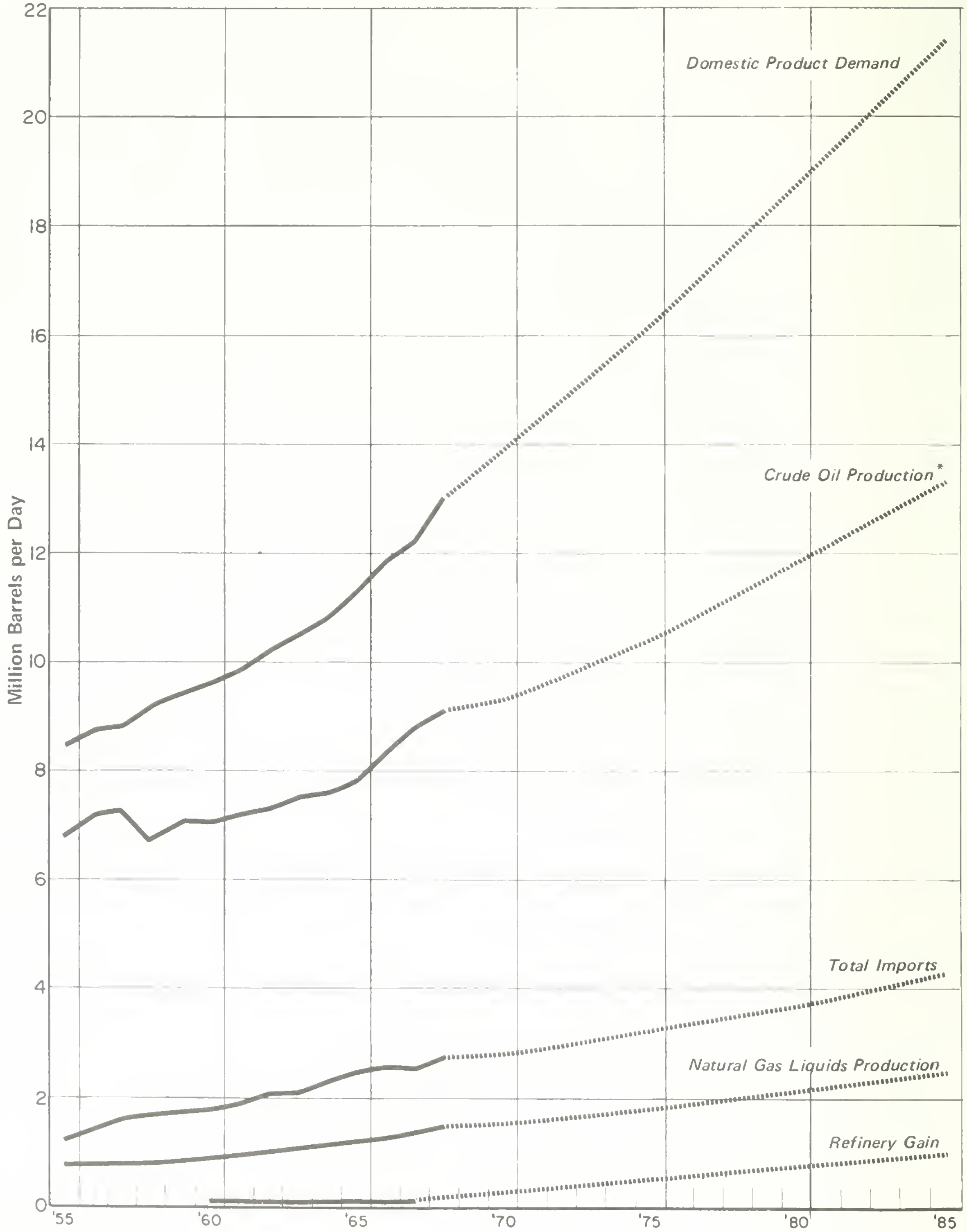
Because of the size of the indicated discovery of substantial crude oil reserves on the North Slope of Alaska, it is concluded that there will be adequate U.S. crude oil reserves to fulfill estimated requirements through 1985, assuming a continuation of total imports at about 20 percent of domestic demand.

Using a projected range of North Slope production in 1985 of a "low" of 1,500 MBD (thousand barrels per day) to a "high" of 3,000 MBD, and on the basis of a Gompertz analysis of projected future reserve additions from remaining U.S. producing areas, it was found that the national reserve-production ratio would be between 10 and 12 years in 1985, an adequate resource base.

IMPACT OF NORTH SLOPE POTENTIAL ON RESERVE-PRODUCTION RATIO OF REMAINING DOMESTIC CRUDE OIL SUPPLIES



PROJECTIONS OF UNITED STATES PETROLEUM SUPPLY AND DEMAND TO 1985



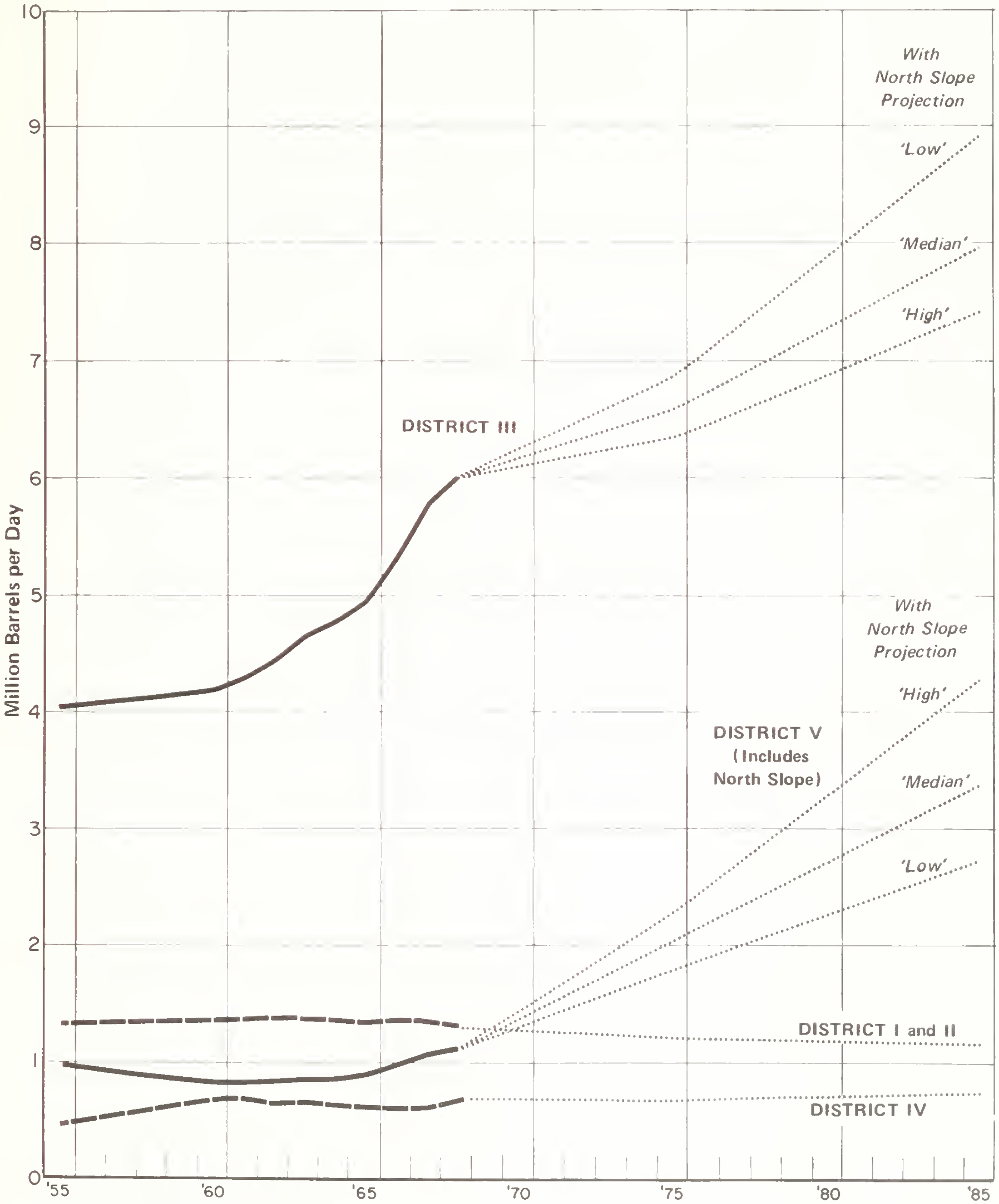
* Includes lease condensate

Without the inclusion of the North Slope, however, it was indicated that the reserve-production ratio would have declined in 1985 to 8.2 years, indicating the need of additional supplies from increased imports and/or synthetic liquids. It is concluded that the need for such supplements to indigenous crude oil supplies is not indicated in the foreseeable future.

(g) Projection of U.S. Crude Oil Production to 1985

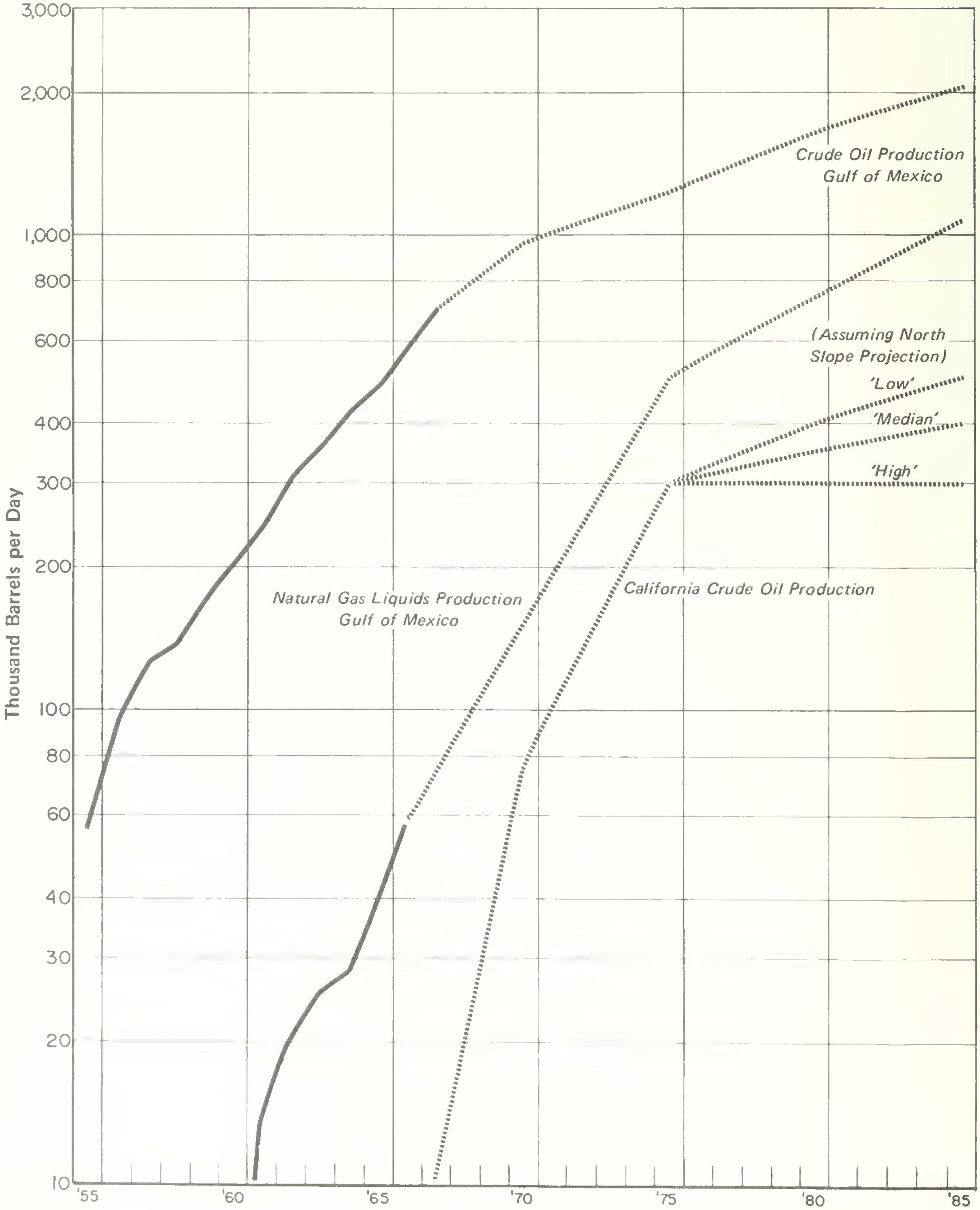
United States petroleum product demand is projected to increase to 16,200 MBD in 1975 and to approximately 21,300 MBD in 1985. To supply this demand, and to maintain total imports in the same

PROJECTION OF CRUDE OIL* PRODUCTION
BY PAD DISTRICTS
TO 1985



* Includes lease condensate

PROJECTION OF CRUDE OIL AND NGL PRODUCTION
FROM GULF OF MEXICO AND CALIFORNIA OCS
TO 1985



historical proportion as under the current mandatory control program, there will be a need for domestic crude oil production to increase to a level of 10,500 MBD in 1975 and approximately 13,500 MBD in 1985, the balance of supply being made up of imports, natural gas liquids, and refinery gain (the excess product output of refineries over liquid inputs).

To reach the anticipated levels of domestic crude oil production during these periods, a growing proportion of the volume is expected from the North Slope of Alaska. By 1985 production from this area is projected to contribute between 11 and 22 percent of projected national production.

(h) Projection of Crude Oil Production by PAD Districts to 1985

Crude oil production in PAD District III (the Southwest), even under the most optimistic assessment of the North Slope potential, is still expected to show continued growth through 1985, when it is projected to range between 7,500 MBD and 9,000 MBD. In 1965 the District's production was approximately 5,000 MBD and by 1968 the estimated production was just over 6,000 MBD.

The sharpest gain in district crude oil production, of course, is forecast for the West Coast because of the inclusion of the North Slope production by at least 1975. Production in the remaining areas of the country (Districts I, II, and IV) is forecast, at best, to maintain its current level, but is more likely to decline as a result of limited new exploratory activity and reduced productive capacity.

(i) Projection of Crude Oil Production and Natural Gas Liquids from the Outer Continental Shelf

Between 1967 and 1985, the volume of crude oil produced from the Outer Continental Shelf is projected to increase at an annual rate of approximately 7 percent per year, or substantially above the expectations of adjacent onshore areas. By 1975 the volume is expected to be approximately 1,500 MBD, or twice the level of production in 1967. By 1985, OCS production is forecast to range from 2,350 MBD to 2,550 MBD. At that time production in the Gulf of Mexico is expected to attain a level of 2,050 MBD. California OCS production, on the other hand, is projected to reach a volume in 1985 of between 300 MBD and 500 MBD, the level dependent on the rate of development on the North Slope.

Particular attention should also be drawn to the potential of the OCS for the production of natural gas liquids. As a result of the predicted strong expansion in natural gas production in the Gulf of Mexico, it is forecast that the total volume of natural gas liquids from this area will be over 1,000 MBD in 1985, representing an important share of the Nation's output at that time.

CHAPTER A
FUTURE ENERGY REQUIREMENTS FOR THE UNITED STATES

I. Summary of Energy Forecast

This Chapter summarizes factors affecting past and future trends of energy demand in the United States and sets out both national and regional overall demand for the two leading energy resources, natural gas and petroleum.

During the past 20 years total energy consumption in the United States has increased from 33 to 59 quadrillion Btu. Over the next 18 years total energy demand is projected to accelerate, reaching approximately 114 quadrillion Btu in 1985, but extrapolated to taper off after 1985 to about 172 quadrillion Btu by the year 2000. A summary of these projections and extrapolations, including historical statistics, is shown on page 113 in the Exhibit section. The same material is illustrated graphically on page 114.

Petroleum has been a leading energy resource, supplying more than 40 percent of the total energy consumed since 1951. However, petroleum's share of the energy mix has been decreasing, having reached a high of 46 percent in 1958, it declined to 43 percent in 1967. A continuation of this decreasing share is anticipated, dropping to about 37 percent in 1985.

Consumption of natural gas, which accounted for 19.5 percent of the national energy total in 1951, has risen steadily and in 1967 amounted to 31.3 percent total energy consumption. Natural gas is projected to continue providing slightly over 30 percent of the energy mix through 1985, but will decline somewhat thereafter.

Other energy resources, coal, hydropower, and nuclear power, taken together are projected to increase their share of the energy market from approximately 26 percent in 1967 to about 33 percent in 1985, and will continue to increase thereafter. The anticipated rapid increase in consumption of other energy resources is due primarily to greater use of nuclear power.

II. Assumptions Used in the Energy Forecast

All energy productions are based on a number of important assumptions, or forecasts, pertaining to the overall economy. Among the more important are the growth in the gross national product (GNP), in industrial production, and in population; the future price interrelationship of alternative energy resources; the economical and physical future supply availabilities; and the evolving technological developments.

For this study the gross national product in constant dollars is projected to grow at an annual average rate of 4.3 percent from 1967 to 1985, compared to an annual average growth rate of 3.9 percent over the last 20 years, and 4.8 percent over the last 5 years.

This estimate for the next 18 years is consistent with the projected annual increase of 2.0 percent in the labor force, compared with the 1.0 percent annual growth in the postwar period generally, with the pace of technological and product development, and with governmental policies directed to avoidance of serious unemployment.[1]

The historical index of industrial production shows an average growth rate of 4.5 percent per year over the past 20 years, and 6.0 percent for the past 5 years. This index is projected at an average annual growth rate from 1967 to 1985 of 4.6 percent.

As to intercommodity price relationships, shifts are envisioned in the market which should be reasonably gradual, and by 1985 should restructure, somewhat, the interrelationship of these prices. While nominal prices for all energy resources may well be adjusted upward in degree to accommodate expected inflationary trends, the cost of "first generation" nuclear energy is assumed to decline both in real dollars and relative to other conventional energy resources. On the other hand, prices of natural gas are assumed to increase somewhat in order to elicit larger volumes of new supplies required to help meet demand. The demand for gas has been and will continue to be affected by the impact of air pollution abatement control throughout most of the United States. This factor will not reach its full impact until perhaps 1975. The air pollution abatement control program will also create a pressure for the manufacturing of low-sulfur residual oil and the marketing of low-sulfur coal, which may force the cost of each upward.

The availability of energy resources is discussed in subsequent chapters of this report, where the petroleum and natural gas supply availability is examined in some detail and possible shifts in supply sources to meet the demand under alternative conditions are analyzed.

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[1] This study also rests on the following general or standard assumptions: (1) no major large scale war but a continuation of defense spending aimed at preparedness; (2) no major catastrophies, such as earthquakes, which might seriously affect industrial and commercial activities; and (3) normal conditions with respect to all variables subject to cyclical or seasonal fluctuations, such as temperatures, business conditions (no major depressions), etc.

Technological changes will continue to affect both the demand and supply of energy. In degree these changes can be anticipated; for example, it is reasonable to assume a continuation of improved techniques in drilling and producing oil and natural gas from the deeper waters of the Outer Continental Shelf. However, "revolutionary" changes which could modify the overall energy technology cannot be anticipated, although they could occur by the year 2000.[1] For example, commercial development of the breeder reactor would have an important effect on the forecasts used in this study. However, revolutionary changes in our overall energy technology are not assumed in this study.

III. Basis for National Energy Projections

National projections of energy demand by resource were made, utilizing not only the studies made by Foster Associates, but also by a careful review of similar recent projections published by others. In Appendix 1, which is included at the end of the text, are shown resumes of the techniques, assumptions, and results of these other studies. A visual comparison of these projections with the energy forecasts used in this report is shown on page 115 of the Exhibit section.

The projections of total energy were constructed in two ways; first by correlation with projections of national economic parameters such as the gross national product and population, and second by a summation of the projections for petroleum, gas, coal, nuclear power, and hydropower. The changing structure of end-use requirements also affects the total energy market. Thus, residential market requirements reflect, among other things, expected changes in population growth rates and variations in per capita energy consumption levels. Industrial energy consumption reflects, among other things, projected growth in the industrial economy, changes in the efficiency of energy utilization and shifts in special markets, especially the transportation and electric power markets.

[1] Implications of what might be dramatic or revolutionary changes in our overall energy technology are discussed in *Patterns of Energy Consumption in the United States, 1947 to 1965 and 1980 Projected*, William A. Vogely and Warren E. Morrison, Bureau of Mines, U.S. Department of Interior. Paper presented at the World Power Conference in Tokyo, Japan, October 1966; and also in *An Energy Model for the United States, Featuring Energy Balances for the Years 1947 to 1965 and Projections and Forecasts to the Years 1980 and 2000*, July 1968, by Warren E. Morrison and Charles L. Readling, Bureau of Mines, U.S. Department of Interior.

In the composite, total energy consumption is projected to increase from 58.8 quadrillion Btu in 1967 to about 79 quadrillion Btu in 1975, to about 114 quadrillion in 1985, and in the proximity of 172 quadrillion by the year 2000.

Petroleum demand in the United States is projected to increase from 11,500 thousand barrels per day in 1965 and 12,600 thousand barrels per day in 1967, to about 16,200 thousand barrels per day in 1975, 21,300 thousand barrels per day in 1985, and in the proximity of 28,300 thousand barrels per day by the year 2000. The transportation sector of the economy commands the greatest proportion of petroleum consumption and is expected to have the strongest influence on petroleum demand, especially through 1985. Petroleum is expected to experience continued growth as a feedstock and as a boiler fuel in industrial markets, the latter influenced in degree by the ability of heavy oils to accommodate increasing air pollution abatement controls throughout the Nation.

Natural gas liquids are included in the data for petroleum. In 1967 gas condensate, LPG, and other gas liquids accounted for 1,400 thousand barrels per day or 14 percent of the total domestic petroleum supply. By 1975 and 1985 natural gas liquids are expected to supply about 15 percent of domestic petroleum supply. Slightly over 60 percent of the natural gas liquids are currently used as a refinery feedstock, and about 40 percent to supply LPG energy and petrochemical demands.

The demand for natural gas is projected to increase from 18.8 trillion cubic feet in 1967 to about 25.8 trillion cubic feet in 1975, 34.8 trillion cubic feet in 1985, and is extrapolated to the proximity of 42 trillion cubic feet by the year 2000. While the largest volume gains are anticipated in the residential-commercial market, it is expected that industrial demands, especially in the process industries, will also increase substantially. Interruptible sales, projected at a slower growth, will continue to be used in competitive markets and as a load balancing factor.

Consumption of other energy resources is expected to increase from 15.3 quadrillion Btu in 1967 to about 22.0 quadrillion Btu in 1975, 37.0 quadrillion Btu in 1985, and is extrapolated to the proximity of 74 quadrillion Btu by the year 2000. The future demand of these other energy resources, coal, nuclear power, and hydropower, is closely tied to the consumption of electricity. Electric power

generation is projected to have the most substantial growth in terms of end-use energy supplies.[1] The above projections anticipate important shifts among competing energy resources with respect to electric power plant consumption, with the lion's share expected to go increasingly to nuclear power, especially during the latter part of the forecast period.

IV. Regional Projections of Natural Gas Demand

Regional projections for the years 1975 and 1985 have been made for the ten regions of the United States as defined by the Future Requirements Committee.[2] The projections for these regions are shown in the Exhibit section on page 116. In general, the national projection of natural gas demand utilized in this report was distributed on a regional basis in accordance with the regional projections set out in the Future Requirements Committee report.

Among the ten regions, the Gulf Coast is the largest producing region for natural gas and also the largest consuming region, accounting for about one-third of the national consumption in 1967. By 1985 this region is expected to consume over 12 trillion cubic feet of gas, approximately 36 percent of the national requirement, showing an annual growth rate well above the national average, as shown below:

	Percent of Total Gas Demand in the United States	
	1967	1985
Gulf Coast	32.4	35.9
Appalachian	17.6	15.8
Pacific Southwest	13.3	12.1
Great Lakes	12.2	12.6
All Others	24.5	23.6
	100.0	100.0

An impetus to this sustained high growth rate for natural gas demand on the Gulf Coast is the proximity of market to supplies, unimpeded by the relatively high cost of gas transportation.[3] A substantial portion of the Gulf Coast market is accounted for by the industrial load which, in turn, is built around a growing petroleum refining-petrochemical complex. It is, in fact, the Gulf Coast gas market that gives the national gas market its strong volumetric growth over the projection period.

The Appalachian region ranking second and the Pacific Southwest region ranking third in natural gas consumption in 1967 are expected to have a slower, annual growth rate to 1985 than that projected for the total United States.

Average annual growth rates above the national average are projected for the Pacific Northwest and the Southeast regions. These two regions, the last to receive natural gas in the United States, still have relatively lower gas saturation levels.

It is interesting to note that the Pacific Northwest, the Great Lakes, and the Northern California portion of the Pacific Southwest, three major regions receiving Canadian gas, exhibit strong growth rates into the future.

V. Regional Projections of Petroleum Demand

Regional projections of petroleum demand have been prepared for the years 1975 and 1985 for each of the five Petroleum Administration for Defense

[1] The projected consumption of coal does not include what may be the conversion of this fuel into pipeline quality gas or into liquid petroleum. The possibility of these conversions taking place over the forecast period are discussed in Chapters B and C.

[2] *Future Natural Gas Requirements in the United States, Volume No. 2,* June 1967, prepared by the Future Requirements Committee, Denver, Colorado. The work of this Committee is sponsored by the American Gas Association, the American Petroleum Institute, and the Independent Natural Gas Association of America. The projections of natural gas requirements made by the Future Requirements Committee are reviewed in Appendix 1.

[3] Generally speaking, the cost of transporting natural gas is several times the cost of transporting an equivalent amount of oil energy.

PETROLEUM DEMAND

Districts	Thousand Barrels Per Day			Percent of Total Demand		
	1967	1975	1985	1967	1975	1985
PAD I	5,015	6,370	8,340	40	39	39
PAD II	3,564	4,530	5,692	28	28	27
PAD III	1,878	2,473	3,323	15	15	16
PAD IV	354	447	585	3	3	3
PAD V	1,749	2,380	3,360	14	15	15
Total US	12,560	16,200	21,300	100	100	100

Districts (PAD) as delineated on page 117 in the Exhibit section. These projections, which are summarized in the Table below, represent a distribution of the national projection on the basis of population growth and per capita consumption in each PAD District.

In 1967 the major consuming areas were PAD Districts I and II, which combined accounted for 68 percent of total U.S. demand. District I is by far the largest consuming region, with some 40 percent of demand. Of the remaining Districts, PAD III and V consumed about equal quantities of petroleum, accounting for some 15 percent each, and PAD IV accounted for about 3 percent of total demand.

The regional projections of petroleum demand to 1985 do not result in any appreciable variation from the national growth rate. Reflecting a slightly lower average growth rate than the Nation, PAD I and II by 1985 are expected to equal 39 percent and 27 percent, respectively, of total U.S. demand. This compares with 40 percent and 28 percent currently. Conversely, demand in Districts III and V is expected to grow at a slightly higher average rate than the Nation with the result that the share of the market attained by them in 1985 is expected to be 16 percent and 15 percent, respectively, as compared to 15 percent and 14 percent currently. Demand in District IV is estimated to continue growing at slightly less than the national average, maintaining its market share at 3 percent.

CHAPTER B
NATURAL GAS SUPPLY AND DEMAND

This Chapter analyzes alternative sources of pipeline quality gas, with special reference to gas produced in the Outer Continental Shelf, which might be available to meet the future demands over the forecast period.

The analysis is based on two independent studies – the supply and demand for natural gas on a national basis, and the supply and demand for natural gas on a regional basis. The results of both studies are integrated and reported in this Chapter. A technical report on the regional study is set out in Appendix 3.

Historically, domestic supplies of natural gas have been capable of producing almost all of the Nation's gas requirements, the balance being supplied by overland imports from Canada and Mexico:

Year	Net Overland Imports as a Percent of U. S. Consumption
1958	0.9
1962	2.7
1967	2.7

The basic question to be answered in this analysis is – To what extent will indigenous supplies of natural gas, including OCS supplies, be capable of meeting future requirements on an economic basis, and to what extent will supplementation from other sources be required?

At the outset it is necessary to measure the net gas production from domestic sources which would be required, assuming a continuation of our present supply-demand structure into the future. After establishing this target of future net production, the analysis will proceed to test alternative sources of gas which might be used to meet these requirements over the longer run. These alternative supplies would be – increased domestic onshore supplies; increase in supplies from the Outer Continental Shelf; increased overland imports; imports of liquefied natural gas; shipments of natural gas from Alaska; and synthetic gas manufactured from domestic coal reserves.

I. Estimated Natural Gas Required to Meet Projected Demand to 1975 and 1985

A projection of the supply-demand for natural gas in the United States must first consider the potential of a continuation of overland imports from Canada and Mexico, as well as a continuation of overland exports of gas from the United States to these two countries.

A. Overland Imports

The current structure of our international trade in natural gas can be demonstrated by reference to the year 1966 when the United States was a net importer of 455 billion cubic feet of natural gas, 2.7 percent of the total U.S. consumption. This net figure was made up of 430 billion cubic feet imported from Canada, 20 billion cubic feet exported to Canada, 50 billion cubic feet imported from Mexico, and 5 billion cubic feet exported to Mexico.

Future exports of gas to Canada and Mexico are expected to level off at less than 100 billion cubic feet per year due to substantial domestic requirements relative to supplies. Imports of Mexican gas are not expected to increase above present levels, but Canadian imports are likely to increase substantially over the forecast period.

Imports of Canadian gas have been increasing, from 10 billion cubic feet in 1956 to 348 billion cubic feet in 1962, and to 513 billion cubic feet by 1967. As to the future, Canadian imports are expected to serve markets within economic reach throughout the northern part of the United States, constrained, however, by potential supply limitations, especially over the latter part of the forecast period. A study of both the economic penetration levels and the supply potential of Canadian gas indicates that U.S. markets within economic reach will import overland (net) about 1.1 to 1.4 trillion cubic feet by 1975, and in the range of 1.5 to 2.0 trillion cubic feet by 1985, extrapolated to a range of 1.5 to 2.5 trillion cubic feet by the year 2000.[1]

This projected growth in overland imports is at a somewhat more rapid rate than the forecast growth in total consumption for the United States. Therefore, net Canadian imports as a percent of consumption are expected to increase from around 2.7 percent in 1967 to 4.7 percent in 1975, and to 5.7 percent in 1985.

B. Projected Net Production Requirements

After subtracting projected overland imports from a forecast of domestic demand, three statistical adjustments must be made to convert the projected gas demand to a net production requirement. First, an allowance must be made for a projected net increase in gas storage; second, an allowance must be made for gas which is vented and flared; and third, a statistical adjustment is required for reporting differences between the U.S. Bureau of Mines consumption data and the American Gas Association

[1] The regional distribution of net imports for 1967 and projected to 1975 and 1985 is shown on pages 80, 81, and 82.

production data, since both sources are relied upon in this study.

After making these adjustments, the net production, which would be required if domestic supplies are to meet the projected demand, is increased from 18.4 trillion cubic feet in 1967 to 24.6 trillion in 1975, to 32.8 trillion in 1985, and is extrapolated to 39.8 trillion in the year 2000.[1]

After establishing a projected net production requirement, the next question is whether the domestic industry is capable of finding and producing sufficient levels of natural gas supplies, within interfuel price levels established by the competitive market place, to meet these requirements.

II. Trends in Natural Gas Production, New Supply and Reserves from 1947 to 1967

Postwar trends in the supply of natural gas in the United States are relevant in anticipating future trends. This section of the report presents a review of national trends, followed by a regional review, and concludes with a review of OCS trends.

A. Review of National Trends

The basic supply trends at the national level are set out on page 118. Net production increased from 5,599 billion cubic feet in 1947 to 13,019 in 1960, and to 18,358 billion cubic feet in 1967, representing annual average growth rates of 6.7 percent from 1947 to 1960, and 5.0 percent from 1960 to 1967. The year 1960 has been chosen for this comparison because in that year the State of Florida commenced to receive, in large volumes, deliveries of natural gas from the Texas and Louisiana Gulf Coast; and this was the last important extensive growth of natural gas in the United States. Prior to 1960 as new major interstate pipelines were constructed and commenced deliveries, new areas throughout the United States received natural gas for the first time. Subsequent to 1960, the growth of natural gas markets was caused by an intensive, as opposed to extensive, growth of existing markets. The fact that net production has continued to grow at a strong rate subsequent to 1960, considering that overland imports were also increasing, is a singular demonstration of the competitive attractiveness of natural gas as a premium fuel.[2]

To supply the increasing demand for natural gas, reserve additions have been discovered and proved in large quantities each year. Reserve additions of natural gas have exceeded production in every year since 1947, and as a result the year-end total of proved gas reserves has increased each year since 1946.[3] Specifically, reserves in the United States have increased from 165 trillion cubic feet in 1947 to 262 trillion cubic feet in 1960, and to 289 trillion cubic feet in 1967; or expressed in average annual growth rates, total reserves increased 3.6 percent from 1947 to 1960, and 1.4 percent from 1960 to 1967. While proved reserves have increased, the national gas inventory has been shrinking relative to requirements and production. This is because production has been increasing at a much faster rate than supplies. The gas inventory, measured by the reserve-production ratio for the United States, has been in a long-term decline from 29.5 years in 1947 to 20.1 in 1960, and to 15.8 in 1967, as shown on page 119. This decline may be seen also by referring to the new supply (additions) to production ratio on page 119 which averaged 1.22 for the period 1960 through 1967, down from an average of 1.88 from 1947 through 1959. An examination of the 3-year moving average shows a long-term decline from a level in excess of 2.0 in the early period to 1.18 for the last 3 years.

Reserve additions result from exploration and well-drilling activity.[4] Therefore, well-drilling activity also explains why our national gas inventory is declining relative to requirements. The trend is shown on page 120. Exploratory wells completed as natural gas producers reached an all-time high of 909 completions in 1959 (up from 365 completions in

[1] See page 129. For comparative purposes, a lower level demand has also been projected to test for sensitivity regarding projected Outer Continental Shelf supplies and other alternative supplies of gas over the forecast period. Specifically, demand is estimated on the lower case level to increase from 18.8 trillion cubic feet in 1967 to 25.1 trillion in 1975, and to 32.3 trillion by 1985. After accounting for overland imports and other adjustments described above, a net production which would be required to meet the lower demand levels is estimated to increase from 18.4 trillion cubic feet in 1967 to 23.9 trillion in 1975, and to 30.3 trillion in 1985.

[2] The average annual growth rate in gas production from 1962 to 1967 was 6.1 percent, and from 1964 to 1967 was 6.2 percent. It is estimated, on the basis of preliminary data released by AGA, that gas production in 1968 was 7.6 percent higher than in 1967.

[3] The United States reserve and production data on page 118 and elsewhere throughout this Chapter (except where otherwise noted), excludes Alaska. Any consideration with regard to Alaskan supplies of natural gas in meeting the demands in the Forty-eight States would presumably involve shipments of liquefied natural gas by tanker or extraordinarily long transmission by pipeline. These matters will be considered in a subsequent section of this Chapter.

[4] Unlike crude oil there is little, if any, secondary recovery of natural gas. However, over the forecast period, nuclear stimulation could conceivably increase the amount of economically recoverable natural gas reserves.

1948), but declined thereafter with only 536 completions in 1967. Developmental gas well completions have followed a similar pattern, but with a time lag, increasing from a level of 3,200 completions on the average for 1946-55, peaking out at 4,674 wells in 1961, and declining thereafter to 3,079 wells in 1967.

B. Review of Regional Trends

Within a national analysis of domestic supplies there are wide differences among the eleven major producing areas shown on page 121. The areas shown on the Tables are primarily patterned from Federal Power Commission pricing areas. These differences are highlighted on the Tables shown on pages 122, 123, and 124.[1]

The most important regional supply feature is the extraordinary position of South Louisiana, including offshore. Production has increased nearly five-fold and proved reserves have doubled since 1956. By 1967 South Louisiana accounted for 29.3 percent of gas production in the United States, up from 12.8 percent in 1956. A second point of considerable importance is that reserve additions have surged to high levels in South Louisiana, yet total reserves have declined relative to net production over the 12-year period. As a result, the reserve-production ratio has declined from 28 years in 1956 to 15 years in 1967.

To fully understand trends in South Louisiana, it is necessary to separate offshore from onshore, especially since 1962. Over the period 1962 to 1967, estimated offshore additions[2] to gas reserves have amounted to 22.7 trillion cubic feet, greater than the 22.1 trillion added onshore. Yet offshore production amounted to only 5.8 trillion cubic feet over this 6-year period, one-third of the 17.9 trillion produced onshore. Thus, onshore South Louisiana has borne the brunt of supplying a considerable portion of the growing national demand, which has reduced the onshore reserve-production ratio to 13.1 years as of December 1967. In contrast, the reserve-production ratio for the Louisiana offshore as of December 1967 stands at 20.0 years, a fact that will support substantial growth in offshore production in the future.

Trends in the Permian Basin area have been somewhat different from those of South Louisiana. Production from the Permian remained almost constant from 1956 to 1963, but in 1964 began to increase, amounting to 9.2 percent of national production in 1967. This increase is projected to continue, at least into the near-term future. The reason for this change in the production trend is evident from examination of annual reserve additions, which were at a substantially higher level in 1964 and thereafter, reflecting the results of successful gas well drilling in the deep Delaware-Val Verde Basin. Because of this strong new supply trend in recent years, the ratio of reserve additions to net production, which previously was relatively low, has substantially increased to a level in excess of 2.5:1.0. This turn-around in supply is evidenced also by examination of total proved reserves, which tended to decline from 1956 to 1963, but then increased from 22 trillion to 32 trillion cubic feet in 1967. As a result the reserve-production ratio, which had declined to a low of 15.4 by 1964, began to increase and reached 18.9 in 1967. The Permian Basin prospectively represents an important source of gas reserves to both interstate and intrastate gas pipelines.

Trends in the Texas Gulf Coast have followed yet a different pattern. The reserve-production ratio in this area has been historically high compared with other important producing areas. For a number of years a considerable reserve of gas was set aside in the expectation of transporting Texas Gulf Coast production to Southern California. However, this expectation failed, and these reserves in recent years increasingly have been dedicated to the rising demand of the industrial market in the Texas Gulf Coast. Offshore Texas supplies also have been dedicated to these industrial markets. The flow of gas from this area to intrastate markets accounts in large degree for the increase in production in recent years which, in 1967 amounted to 20 percent of national production.

Reserve additions of natural gas on the Texas Gulf Coast have remained at high levels, but with an increasing production level in recent years they have just been able to replace production, holding the total proved reserves at a relatively constant level since 1961. With the reserve-production ratio currently at 19.5, a further substantial increase in production can be forecast for this area. This potential could be considerably enhanced, of course, if substantial reserve additions are proved-up in the Texas OCS.

The Hugoton-Anadarko area, while accounting for 16.4 percent of 1967 gas production in the United States, has been unable to replace its growing production since 1959. As a result, proved reserves in the Hugoton-Anadarko have been in a long-term

[1] Area data commence in 1956, the first year in which the American Gas Association Committee on Natural Gas Reserves reported separately supply information on a functional area basis. Detailed schedules for the most important areas are set out as Appendix 4.

[2] See Section II of this report for explanation of the techniques of estimation.

decline, as has the reserve-production ratio. The reserve-production ratio declined from 21.6 in 1961 to 13.8 in 1967.

The Other Southwest Area is another important producer of natural gas in the United States, accounting for 13.2 percent of total 1967 national production. Yet, net production has been virtually constant since 1956. Until 1966 reserve additions have been able to approximately replace production, but in 1967 additions fell substantially below production levels and total reserves declined. The reserves-to-production ratio was at 12.2 in 1967.

Natural gas production in the San Juan Basin, the Rocky Mountain States, and in California has ranged between 500 and 700 billion cubic feet in each area in recent years. Reservoirs in the San Juan Basin have been troubled by permeability problems, resulting in substantial downward revisions in 1959 and 1960. It is in this area, and portions of the Rocky Mountains, that there are prospects for new supplies by nuclear stimulation. Aside from local consumption most of the San Juan gas is shipped to California. Rocky Mountain supplies are consumed locally. California production is consumed intrastate, supplemented increasingly by interstate shipments from the Permian Basin, San Juan Basin, and from Canada, in order to meet growing demands. In 1968 utilization of oil well gas from the California OCS commenced in Southern California. Reserve-production ratios in 1967 were 18.9 for the San Juan Basin, 15.9 for the Rocky Mountain area, and 12.0 for California.

C. OCS Supplies of Natural Gas from 1947 to 1967

The offshore supplies of natural gas through 1967 were in the Gulf of Mexico.[1] The estimated production, reserve additions, and total reserves of gas in the Gulf of Mexico from 1947 to 1967 are set out on page 125. These estimates are derived by analyses of data reported by the American Gas Association Natural Gas Reserves Committee, the Louisiana State Department of Conservation, and the Texas Railroad Commission. The statistical techniques used in making the estimates are described in Section II of this report. For the purpose of this analysis, the OCS portion of the Gulf of Mexico is defined in Louisiana as seaward of The Chapman Line, and in Texas as seaward of the coast line. These definitions are consistent with those employed by the American Gas Association Natural Gas Reserves Committee.

As of December 1967 total proved reserves in the offshore area were reported at about 34.2 trillion cubic feet, of which 32.4 trillion are estimated to be located in the Louisiana portion and 1.8 trillion in the Texas portion. Production in 1967 amounted to 1,797 billion cubic feet, of which 1,624 billion cubic feet were from the Louisiana portion and 173 billion cubic feet from the Texas portion. The reserve-production ratio as of December 1967 was 19.0 for the Gulf of Mexico OCS.

The Louisiana OCS has played a very important role in making South Louisiana the most important natural gas province in the United States. Annual reserve additions have been especially strong since 1961. On the basis of estimates for the years 1962 through 1967, reserve additions in the Louisiana OCS exceeded the onshore additions in 4 of the 6 years, and accounted for 22.7 trillion cubic feet or 50 percent of the total reserve additions in South Louisiana. Net production of natural gas in the Louisiana OCS area also commenced to increase substantially about 1961, and by 1967 production amounted to 1,624 billion cubic feet or twice the 1964 level of 762 billion cubic feet. Even so, a substantial amount of proved reserves in the Louisiana Gulf of Mexico are still "waterlocked," a situation which will change rapidly over the next few years as an increasing number of natural gas pipelines extend their gathering systems to these OCS reserves. Considering the high levels of reserve additions experienced in offshore Louisiana, the leasing and drilling activities, and estimated gas reserves remaining to be found, it seems reasonable to anticipate this area becoming one of the most important, if not the most important, producing area in the United States.

In Texas new supplies of offshore natural gas have been quite sporadic and of magnitude only in the last two years. These supplies were quickly contracted for industrial consumption onshore Texas, accounting for the substantial increase in 1967 production. Yet leasing and exploratory drilling activity in the Texas OCS, and potential reserve estimates, suggest a much more important role will be played by this area in the future.

III. Estimates of Potential Domestic Gas Reserves

Having established future requirements for domestic gas, it is necessary to ascertain whether these requirements can be met from domestic natural gas reserves.

[1] In 1968 supplies from the Santa Barbara Channel were contracted to the local gas distributing company. Therefore, these supplies of casinghead will commence to supplement the other sources of gas in Southern California.

The question of domestic reserves sufficiency immediately breaks down into two sub-questions:

(1) Will estimates of the economically recoverable natural gas reserves in the United States, if discovered, be sufficient to support the necessary growth in production?

(2) Will the exploration and development at levels sufficient to "prove-up" econcomically recoverable reserves be timely to meet the annual growth in production requirements?

Factors which influence the answers to these questions must be explored in order to assay the future role of OCS supplies.

This section will probe into the estimates of economically recoverable natural gas reserves in the United States. A summary of these estimates is set out on page 127.

A. The National Resource Base and Economically Recoverable Reserves

There have been a number of estimates made of the petroleum and gas resource base in the United States, the more recent estimates being made by Hendricks in 1965 and Hendricks and Schweinfurth in 1966.[1]

The 1965 Hendricks' publication estimates that natural gas resources in place are about 4,000 trillion cubic feet based on a 2,500 cubic feet per crude oil barrel ratio. Some 2,500 trillion cubic feet of this 4,000 trillion cubic feet resource base are estimated as available "to be found by exploration." Assuming an 80 percent recovery factor, the author estimates economically recoverable reserves to be 2,000 trillion cubic feet. These estimates included reserves to only 120 feet of water in the Gulf of Mexico and the Pacific OCS. Apparently no estimates were included for the Alaska OCS.

These area omissions were, however, included in the 1966 estimate when Hendricks and Schweinfurth broadened their geographical base to include the Gulf of Mexico, Pacific and Alaska OCS out to 600 feet of water. It is uncertain whether the Atlantic OCS is included in either of these two estimates. Using the same ratios employed by Hendricks (in the 1965 publication), this more recent and broadened study indicates a resource base on 5,000 trillion cubic feet, of which some 2,500 trillion cubic feet are economically recoverable.

[1] Hendricks, T. A., *Resources of Oil, Gas and Natural Gas Liquids in the U.S. and the World,* U.S. Geological Survey Circular 522, 1965. Unpublished memorandum dated September 14, 1966 by Hendricks, T. A., and Schweinfurth, S. P., as reported in *United States Petroleum Through 1980,* U.S. Department of Interior, 1968 page 11.

A third estimate was set out in *Natural Gas in the United States as of December 31, 1966,* prepared by the Potential Gas Committee (PGC).[2] The PGC estimated natural gas reserves in the United States extending out to 600 feet of water depth in the OCS, but did not include Alaska either onshore or OCS. No resource base estimate was published by the PGC. Economically recoverable reserves were estimated at 1,290 trillion cubic feet.

In summary, the PGC and the Hendricks and Schweinfurth material provide a range of 1,290 to 2,500 trillion cubic feet for economically recoverable natural gas reserves in the United States. This wide range cannot be reconciled, indicating the considerable uncertainly expressed by the authors in estimating future potential natural gas reserves.

A certain portion of the economically recoverable reserves have already been discovered, and in part produced. According to the PGC report, cumulative natural gas production in the United States as of December 31, 1966 amounted to 314 trillion cubic feet, and proved reserves in the United States were 286 trillion cubic feet as of December 31, 1966.

Therefore, economically recoverable natural gas reserves in the United States potentially remaining to be discovered are estimated in a wide range, 690 to 1,900 trillion cubic feet.

The PGC estimate of 690 trillion cubic feet, characterized as "potential supply," is broken down into three categories of approximate probability of discovery, and also into three geographic areas.

An explicit assumption was made by the PGC in regard to incentive and technology:

> "The explicit assumption of adequate but reasonable prices and normal improvements in technology in the definition of potential supply relates to improvements in exploration techniques and drilling to greater depths at increasingly difficult locations. Adequate prices and normal technological improvements are required to bring about the drilling necessary to prove the potential supply which may exist at greater depths and in deeper offshore waters . . . At the same time, prices must be at a reasonable level if the volumes found are to be produced and sold."*op. cit.*, page 22.

This assumption, also implied by Hendricks, provides a reasonable basis for further analysis of the future annual finding rates of proved natural gas reserves. However, before proceeding to this analysis, it is useful to review potential reserve estimates for the OCS, an important part of the national estimates.

[2] This Committee is sponsored by the American Gas Association, the American Petroleum Institute, and the Independent Natural Gas Association of America.

Supply Area	Probable	Possible	Speculative	Total
East	55		60	115
Central	220	170	80	470
West	25	40	40	105
Total	300	210	180	690

B. Estimates of Potential Natural Gas Reserves in The Outer Continental Shelf

A recent definitive study of the oil and gas potential in the Nation's OCS is included in *Potential Mineral Reserves of the United States Outer Continental Shelves*, McKelvey, V. E., and others, U.S. Geological Survey, 1968, in press. Several reserve estimates are included in this publication. Those "based on extrapolation of results of drilling . . . . estimated from data to January 1, 1966," will be used in this analysis. The natural gas estimates may be summarized as follows, in trillion cubic feet:

"Interpreted in this perspective, OCS recoverable reserves may be thought of as ranging from about 35 billion barrels of liquids and 170 trillion feet of gas in geologically known areas to something approaching 180-220 billion barrels of liquids and 820-1,100 trillion cubic feet of gas in the entire shallow shelf terrane; taking account of future advances in technology that will permit improved discovery and recovery as well as production from the deeper parts of the OCS, some now unpredictable part of the marginal and submarginal resources may be recoverable eventually."

		Out to 200 Meter Isobaths	200 to 2,500 Meter Isobaths
1	Total potential resources in the ground	1,640	1,590
2.	of which,		
	a. Recoverable under current economics and technology	820	0
	b. Marginal and submarginal	820	1,590

The focal point is the 820 trillion cubic feet estimated to be recoverable under current economics and technology, which is broken down into OCS areas by the Geological Survey study, as follows:

O C S Areas	Trillion Cubic Feet
Gulf of Mexico	300
Pacific	38
Alaska	271
Atlantic	211
	820

Approximately 14 percent of the Gulf of Mexico reserves, 42 trillion cubic feet, had been proved-up as of December 1966, leaving 258 trillion cubic feet in the Gulf and 778 trillion cubic feet in the total OCS potentially remaining to be discovered. (page 127).

After discussing other prior estimates, McKelvey concludes:

These OCS estimates by McKelvey coincide geographically with the 1,900 trillion cubic feet estimated by Hendricks and Schweinfurth to be economically recoverable for the Nation. Therefore, these estimates suggest that approximately 40 percent of the Nation's remaining economically recoverable reserves exist in the OCS.

Quite a different result is obtained by arithmetically comparing McKelvey's estimate excluding Alaska with the PGC national estimates. The OCS potential natural gas reserves of 507 trillion cubic feet are about 70 percent of the Nation's remaining recoverable natural gas reserves estimated by the PGC at 690 trillion cubic feet. The reason for the wide variance in the ratios presumably arises from differences in methodology used in preparing these estimates. An arbitrary averaging of the PGC and the Hendricks and Schweinfurth estimates would yield approximately 1,300 trillion cubic feet of remaining recoverable reserves in the United States, about a 30 percent discount on the Hendricks and Schweinfurth 1966 estimate. Application of this 30 percent

discount to McKelvey's estimate yields 545 trillion cubic feet of remaining recoverable reserves in the OCS, about 40 percent of the Nation. These estimates are, of course, only the results of averaging two widely different estimates in order to provide one reconciliation point. The 40 percent ratio will be utilized as an analytical tool in subsequent sections of this report.

C. Summary

There is ample evidence of very considerable gas reserves remaining to be discovered in the United States. While estimates of these reserves vary widely, one mid-point estimate would be 1,300 trillion cubic feet within technological and economical reach, of which some 40 percent are under the OCS. These potential reserves may be compared with some 600 trillion cubic feet of gas discovered in past years (of which 314 trillion cubic feet have already been produced, leaving 286 trillion cubic feet as proved reserves, an inventory to support future production).

Given this considerable reserve potential, the next question is the rate at which these potential reserves will be discovered and developed into annual additions to proved reserves. This rate will depend on the timing of exploration and developmental well drilling activity, the subject of the following section.

IV. Projected Supplies of Natural Gas Available to Meet Domestic Requirements from 1968 to 1975

The transformation of natural gas reserves from a "potential" to a "proved" category is reported annually by the American Gas Association, which breaks down additions to natural gas reserves into (1) new field and reservoir discoveries and (2) extension and revisions of previous discoveries. The trends in these two components of additions to reserves are shown annually over the period 1956 to 1967 on page 128. Annual reserve additions have fluctuated widely over this period, ranging between 25 trillion cubic feet in 1956 and 14 trillion cubic feet in 1960. There is no apparent secular trend in reserve additions over this review period. Average annual new supply amounted to 19.5 trillion cubic feet from 1956 to 1967, and to 20.5 trillion cubic feet over the last three years reported.[1] The most important part of reserve additions are new discoveries in the sense that new fields and new reservoirs will be further developed in subsequent years. Annual new discoveries have fluctuated from a low of 5.4 trillion cubic feet in 1967 to a high of 9.0 trillion cubic feet in 1957. Again, there is no apparent secular trend, although the average for the last 6 years of 6.1 trillion cubic feet was slightly lower than the average of 6.6 trillion cubic feet over the previous 6 years. Over the last 3 years new discoveries have averaged 6.0 trillion cubic feet.

A. Projected Reserve Additions from 1968 to 1975

A number of factors have undoubtedly caused reserve additions to remain in a static posture over recent years. Perhaps the most important of these factors is the belief by the production segment of the industry that field price levels and regulatory uncertainties have unduly depressed the incentive to drill for gas reserves, in comparison with the attractiveness of expending funds on alternate opportunities.[2] In varying degree, this viewpoint has been expressed by others.[3]

As shown on page 120, both exploratory and developmental gas well drilling have declined substantially in recent years. Since gross reserve additions have held up, it follows that the quantity per gas well has increased. However, there are several reasons why the relatively larger gross reserve additions per gas well drilled may not be representative for the future. First, the quantity of reserves found in recent years, including the reserves which ultimately will be reported as extensions and revisions of estimates, will not be known for many years in the future. The reserve additions reported annually as extensions and revisions are related to the discoveries of many prior years. Second, the decline in developmental drilling lagged the decline in exploratory drilling, so that extensions and revisions of estimates as reported in recent years probably are related to exploratory drilling of prior years in greater than average degree. Third, extraction of natural gas

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[1] While reserve additions have remained static at the national level, dynamic and diverse trends are taking place on a regional basis. For example, reserve additions in the Gulf of Mexico and in the Permian Basin have been increasing in recent years, offsetting declining trends in other regions. See regional discussions above. Also see Appendix 4 for more details.

[2] See, for example, U.S. Federal Power Commission, Docket Nos. AR61-2 et al (South Louisiana Area Rate Proceeding), *Application for Rehearing of Indicated Respondents* (Amerada Petroleum Corp., et al) undated (September 1968).

[3] See, for example, "Impact of Area Pricing on Production and Demand," Chandler, M. C., and others, *Public Utilities Fortnightly*, October 10, 1968; U.S. Commission on Marine Science, Engineering and Resources, *Our Nation and the Sea: A Plan For National Action*, January 9, 1969, preprint; *Economic Report of the President Together With The Annual Report of the Council of Economic Advisers*, January 1969, Washington, D.C.; Kitch, Edmund W., "Regulation of the Field Market for Natural Gas by the Federal Power Commission," *Journal of Law and Economics*, October 1968.

is inherently a business of declining productivity and rising real cost. Average productivity of drilling for gas in the United States has been held up by the shift from older to newer, more prolific geological areas. Thus, estimated reserve additions per well drilled are far higher in the onshore South Louisiana area than in the rest of the Continental United States (as a composite), and are higher offshore than onshore (Section II, Exhibits Section, pages 215 and 216). The uncertainty concerns the number of new areas that may be found. Fourth, productivity of drilling depends upon level of activity. If the decline in drilling activity were reversed in response to stronger incentives for investment, relatively more marginal known prospects would have to be explored. The increase in quantity of gas found or in gross reserve additions as reported probably would be at a lesser rate than the increase in exploratory activity.

Assuming the price incentive and other factors to remain unchanged, it seems appropriate to project future average reserve additions at no more than 20.5 trillion cubic feet, the average over the last 3 years. The implication of this assumption may be summarized statistically as follows:

On the assumption that present depressants affecting gas drilling incentive will be removed but that field prices will remain within the constraints of the market place, it is possible to construct an orderly progression of future reserve additions to respond to increasing demands and production requirements.[1] Yet it is necessary to recognize that there is a lead time stretching over several years before an increased exploration and development program can be translated into production requirements. Therefore, any increase in incentives must precede by several years the build-up in reserve additions to match the build-up in demands.

In order to establish a reasonable projection of reserve additions to 1975, it is helpful to examine projections by three independent techniques, or methods:

1. Reserve additions may be determined as a first derivative of total cumulative proved gas reserves projected on the basis of a Gompertz curve fitted to a historical time series of reserves reported by the American Gas Association Committee on Natural Gas Reserves.[2]

Trend in Domestic Gas Reserves Assuming Annual Reserve Additions Remain at Recent Levels

Year	Reserve Additions	Production	Total Reserves	RPR
		(Trillion Cubic Feet)		
1968	20.5	19.0	290.8	15.3
1970	20.5	20.8	291.2	14.0
1973	20.5	23.1	285.8	12.4
1975	20.5	24.6	278.4	11.3

In short, a continuation of reserve additions at recent levels would cause additions to be exceeded by production requirements by 1970, with total reserves declining thereafter, and the reserve-production ratio falling below 12 years after 1973, reaching 11.3 years by 1975.

The fact of production exceeding reserve additions after 1970, and of total proved reserves declining, must be considered an unacceptable trend which would only be compounded into the future. Therefore, it is assumed that the economic structure currently attending exploration and production of natural gas will be modified sufficiently to bring forth the higher level of reserve additions required to support the demand and production requirements of natural gas into the future.

2. Reserve additions may be projected by adopting the assumption that on the average the annual new supply will increase at a rate of 2.2 percent per year, in accordance with the conclusions reached by a study set out in a

1 ". . .there seems to be no doubt that natural gas will be a major and vital source of energy for many years to come and nothing should be done at this time which would prevent the exploration and development necessary to make available this clean, convenient, economically and increasingly popular energy source." F. P. C. Opinion No. 546 (South Louisiana Area), at page 125.

2 For an explanation of the Gompertz curve and its uses in analyzing and projecting finding rate trends, see Moore, C. L., *Projections of U.S. Petroleum Supply to 1980,* Office of Oil and Gas, Department of Interior, 1966.

recent publication by the U. S. Department of Interior.[1]

3. Reserve additions may be projected by assuming on the average the annual additions will replace production.

Using average annual additions of 20.5 trillion cubic feet for 1965-67 and 21.1 trillion cubic feet for 1967 as points of reference, the projected annual additions according to these three methods would be: 1975. Over the 8-year period some 186 trillion cubic feet of natural gas are projected to be added to the national proved reserves, about 14 percent of the potential economically recoverable reserves (1,300 trillion cubic feet) estimated at the beginning of this period.

The interrelationship of projecting reserve additions, production requirements, and proved reserves to the year 1975 can now be examined.

Projected Annual Additions to Domestic Gas Reserves

(Trillion cubic feet)

Year	Based on the Gompertz Curve	Based on the Dept. of Interior Study	Replace Production
1970	21.4	22.5	20.8
1975	22.2	25.0	24.6
Cumulative, 1968-1975	173.2	186.0	174.9

Projected Reserve Additions Compared with Production Requirements

Year	Reserve Additions	Production	Cushion
	(Trillion Cubic Feet)		(Percent)
1968	21.5	19.0	13.2
1973	24.0	23.1	3.9
1975	25.0	24.6	1.6

As a matter of judgment, the Interior method of projection seems quite reasonable for the period 1968 to 1975 and therefore will be adopted as a guideline for the purpose of projecting the national reserve additions, excluding Alaska, from 1968 to the year

[1] *United States Petroleum Through 1980,* Office of Oil and Gas, Department of Interior, 1966, at page 24. Also see address of Onnie P. Lattu, Director, Office of Oil and Gas, to the Independent Natural Gas Associatiion of America, October 28, 1968.

B. Production and Proved Reserves of Natural Gas Projected from 1968 to 1975

Over the 8-year period to 1975 projected reserve additions will continue to exceed, but by a decreasing margin, gas production required to meet demands (after allowing for overland imports). In 1968 reserve additions are projected to exceed production by 13.2 percent, in 1973 by 3.9 percent, and in 1975 by 1.6 percent.

It is clear that the two projected trends are converging and if extended to 1976 the two series would converge.

The comparative projection of total reserves and production over the period would be as follows:

and distributors, what inventory is required to assure a sufficient physical supply in order to allow for planning of capital expenditures needed to expand service in order to meet growing demands?

These questions are deserving of a responsive

Projected Total Proved Reserves Compared with Projection Requirements

Year	Total Reserves	Production	Reserve-Production Ratio
	(Trillion Cubic Feet)		
1968	291.8	19.0	15.4
1973	299.3	23.1	13.0
1975	300.4	24.6	12.2

Although proved reserves will continue to increase, production requirements are increasing faster and, therefore, the reserve-production ratio declines from 15.4 in 1968 to 12.2 in 1975.

Total reserves will peak out in 1976 and commence to decline thereafter, and the reserve-production ratio will decline quite sharply after the peak reserves have been passed.

Thus, even assuming a reasonably optimistic trend in reserve additions, it is clear that the substantial growth in production requirements will continuously reduce the relative national inventory of natural gas. It is therefore useful to interject into the supply and demand trend inquiry, an examination regarding factors affecting the minimum inventory of natural gas which should be maintained in the United States.

C. Factors Affecting Minimum Gas Inventories in The United States

It is apparent from the analyses set out in the preceding sections that the strong increase in gas demand causes a continuing decline in the national reserve-production ratio. The projection of reserve additions increasing by 2.2 percent per year will positively slow down this decline, but even so, by 1975 the reserve-production ratio would be at 12 years, and would reach 10 years by about 1980 if these trends continued beyond 1975.

How far should the national reserve-production ratio be allowed to decline? From the viewpoint of the consuming public what gas inventory should be maintained to assure reliability of continuous deliveries?[1] From the point of view of gas pipelines

[1] In this regard it should be kept in mind that on the basis of the Commission's method of price regulation, consumers ultimately bear the cost of maintaining a gas inventory.

answer, but to date no authoritative study on this subject has been prepared. In seeking guidelines for the problem, the study would have to come to grips with a host of considerations, including geological characteristics of reservoirs, economical and institutional factors, Federal Power Commission supply requirements for regulated pipelines, interstate and intrastate contracts between producers and pipelines, and regional supply-demand trends.

It is also important to consider the deliverability, or reservoir capacity, of gas reserves (deliverability being defined as full load life of gas reservoirs at current producing rates).[2]

[2] The deliverability of gas reserves as used in this study is measured on an annual basis and, therefore, is different from productive capacity of gas reserves, which is measured on a 90-day basis. The American Gas Association started reporting productive capacity of gas reserves in 1966. To fully understand productive capacity data it would be necessary to analyze the manner in which heating season demands are met by pipelines and distributors, including the relative use, on a regional basis, of gas storage, peak shaving, and load balancing, as well as increased withdrawals from producing fields. The distinction between productive capacity as measured for gas compared with the measurement for oil is also of significance. This distinction was described by the American Gas Association as follows:

"The productive capacity of natural gas must be viewed differently from the productive capacity of crude oil. Adjustments and changes in oil well equipment which can be made within ninety days to attain maximum rates of production are not applicable to non-associated gas wells. Also, oil can be stored in tanks near the area of production and transported to a refinery or market by truck, tank car or tanker, as well as pipline. Gas, after leaving the well, can only be carried to the market in large volumes through pipelines . . . Therefore, productive capacity of natural gas, as used in this report, is not a measure of current availability of gas for consumption, as present available facilities limit the quantity of gas that could be produced and transported for use."

Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1967, Volume 22, May 1968, pp. 114-116; published jointly by: American Gas Association Inc., American Petroleum Institute, and Canadian Petroleum Association.

Due to the depletion characteristics of gas reservoirs, the deliverability life of proved reserves will always be less than the reserve-production ratio. However, there is no certainty regarding the relationship between deliverability life and the reserve-production ratio. Various estimates suggest the difference between these two national supply measurements is in a range of 4 to 8 years, based on annual average production.[1] Assuming the difference between the two supply measurements to be 6 years regardless of change in the reserve-production ratio, then the current national reserve-production ratio of about 15 years would equate to a deliverability life of about 9 years, a reserve-production ratio of about 12 years would equate to a deliverability of about 6 years, and a reserve-production ratio of 10 years would equate to a deliverability life of about 4 years.

In appraising these relationships, it is difficult to envision the industry maintaining an assured continuity working with only a 4 year deliverability life, and perhaps even a 6 year deliverability life. The reasons are (1) the lead time between investment incentives, the making of expenditures and availability of proved reserves to pipelines, and (2) the uncertainty regarding quantity of new reserves which may be found from year to year. The shorter the deliverability life the greater the dependence on a consistently high discovery rate of proved gas reserves, region by region.

A deliverability life below 6 years would assume that reserve additions of gas in the United States will be predictable in an orderly manner into the future, and that with virtually no time lag, these supplies would be made available and withdrawn by gas pipelines. These would seem to be hazardous assumptions. By the very nature of drilling for hydrocarbons, the annual finding rates are erratic (see Appendix 4, page 83, and Table shown on page 118) and cannot be predicted from year to year, a fact which could create serious problems if low finding rates are experienced over several consecutive years. And if finding rates are low, as a matter of economics the limited new supplies will flow primarily to local markets in the Southwest. Since these are the largest markets in the United States and are projected to grow at a faster rate than the total United States, there will tend to be a declining portion of annual new reserves made available to those pipelines who transport gas to more distant markets.

[1] For example, see testimony of R. D. Grimm and M. H. Cullender in the South Louisiana Area Proceeding, Docket Nos. AR61-2, et al. It should also be noted that the differential between the reserve-production ratio and deliverability life will vary substantially between areas, due primarily to reservoir characteristics.

Presumably this is a future supply assurance problem, but it could well relate to near-future deliverability shortcomings in certain producing fields or areas during periods of peak withdrawals. It could represent a harbinger of increasing additional supply shortcomings as the national reserve-production ratio drops below 15 years.

In view of these considerations, a *minimum* national natural gas inventory, represented by a 12 to 1 reserve-production ratio is adopted as the standard for the purpose of this study. This assumption is not inconsistent with the conclusion reached by the Office of Oil and Gas, Department of Interior, in its 1968 publication *United States Petroleum Through 1980*, that a national reserve-production ratio of 11.9 "appears to be too low," and instead utilized as "an arbitrary assumption" a national reserve-production ratio standard of 15 to 1 projected to the year 1980.

The 12 to 1 standard also coincides with the domestic reserve-production ratio for crude oil which for many years has fluctuated around 12 years.[2]

A 12 year national reserve-production ratio standard is not equally applicable to all producing regions, but represents a composite of the area data. The 1967 reserve-production ratios on an area basis, were as follows:

	Reserve-Production Ratio As of December 1967
South Louisiana Offshore	20.0
Texas Gulf Coast	19.5
Permian Basin	18.9
San Juan Basin	18.9
Rocky Mountain	15.9
Hugoton-Anadarko	13.8
South Louisiana Onshore	13.1
Other Southwest	12.2
California	12.0

[2] The average reserve-production ratio for crude oil in the United States has been 12 years for the period 1956 to 1967. However, this average was based on the relationship of production and "proved" crude oil reserves. In 1966 and 1967 "indicated additional" reserves, when added to "proved" reserves, increased the reserve-production ratio in both years by 2-1/2 years. Additional crude oil reserves include additional known reservoirs (in excess of the proved reserves) which will be economically available by application of fluid injection. The introduction of these additional reserves added to proved reserves suggests that the reserve-production ratio for crude oil in the United States has been somewhat higher than the 12 years indicated above. See Chapter C of this report for more details. It should also be noted that "additional" reserves are not reported for natural gas. This is because recovery rates for natural gas reserves are about 80 to 85 percent. Moreover, the proportion of total domestic product demand supplied from sources other than crude oil production has increased from about 20 percent in 1956 to 33 percent in 1967.

The reserve-production ratios shown above on an area basis exist in a wide range for a number of reasons, including variances in exploration, productivity of well drilling, deliverability and producibility of proved reserves, the mix of reserves as between non-associated and associated-dissolved, the location of major pipelines, and growth rates in markets served. It should not be expected that the reserve-production ratio for each of these areas will systematically decline to the 12 year minimum. Reserve-production ratios for some areas may be expected to decline below 12 years and for other areas remain above 12 years.

D. Factors Which Could Affect The Terminal Year of The First Phase of Projected Gas Supply

Having projected a minimum inventory requirement measured at the national level by a reserve-production ratio of 12 years, it is immediately apparent that this minimum level would be reached by 1975 based on assumed increases in reserve additions. Therefore, 1975 represents the terminal year of the *first phase of projected gas supply.*[1]

With the industry supply and demand in virtual balance with minimum inventory requirements by about 1975, it becomes apparent that either the average level of reserve additions must necessarily be increased in order to maintain our domestic gas inventory at the desired minimum level, or substantial supplementation will be required from other sources. This change, then, marks the commencement of the *second phase of projected gas supply.*

Before proceeding with the analysis of this second phase, two additional topics should be discussed—factors which could affect the terminal year of the first phase, and the important contribution to be made by the OCS during the first phase of gas supply.

There are three vital input factors which will affect the timing and volumes of natural gas supply and demand over the forecast period and, therefore, the terminal date for the first projected phase. They are, (1) the demand, (2) the annual average addition to reserves, and (3) the minimum inventory requirement. The most probable levels of these input factors are those used in the main flow of this report. However, these, like all projections, are attended by varying degrees of uncertainty. It is therefore useful to digress from this main flow and consider some of the implications of alternate levels.

First, some authorities would argue for a lower demand and others a higher demand than used in this report. A lower case demand has been briefly considered and described above. In summary, this lower case demand was approximately 3 percent below the probable demand in 1975, and 8 percent below the probable demand in 1985.[2] The impact of this lower case demand would be to delay by about 2 years the timing of the termination of the first phase. On the other hand, a higher case demand would advance the timing by about 2 years.

Second, there is the consideration that reserve additions might be higher or lower than the levels considered most probable and used in this analysis. Different levels would be reached if alternative assumptions are made regarding exploration and drilling incentives. If no change is assumed in the current 1968 incentive structure, it could be reasonably postulated that future average annual reserve additions will be in a range of no more than 19 to 21 trillion cubic feet, in which event the terminal date of the first phase would be accelerated by 2 to 3 years. On the other hand, it is difficult to envisage finding rates higher than the levels assumed in the first phase, primarily because of lead time required in building up exploration and development activity necessary to achieve these higher levels. However, a higher finding rate will be projected in this study for the second phase beyond 1975.

Finally, there is the important assumption regarding the minimum inventory requirement. As discussed above, it is reasonable to believe that the *minimum* inventory requirement is in the range of 12 to 15 years. The lower end of this range is taken for the purposes of this report. If, in fact, minimum inventory requirements should be closer to 15 years rather than 12 years, then the termination of the first phase could occur as early as the 1969-70 or 1970-71

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[1] This first phase would be characterized by domestic reserves continuing to supply domestic requirements, supplemented in a small degree by continued overland importation of gas. Neither liquefied natural gas tanker shipments nor synthetic gas produced from domestic coal are projected to be competitive with domestic supplies over this period.

Tanker shipmates of liquefied natural gas may, however, be landed on the East Coast in small amounts during the first phase, perhaps amounting to 300 million cubic feet per day. These volumes are negligible relative to national requirements. Other shipments of LNG may also be imported from time to time, in small volumes, for peak shaving purposes. \In this regard see Federal Power Commission approval of emergency receipts of Algerian gas by Boston Gas Co., November 1968.

[2] After deduction of overland imports, and adjusting demand to a net production basis.

heating season, a circumstance which might disrupt a considerable portion of the industry and preclude the possibility of an orderly transition from the first to the second phase.

E. Production of Gas in the Outer Continental Shelf from 1968 to 1975

During the first phase of natural gas supply, domestic production is projected to increase from 18.4 trillion cubic feet in 1967 to 24.6 trillion cubic feet by 1975, or by 6.2 trillion cubic feet. Natural gas production in the OCS part of the Nation is projected to increase from 1.8 trillion cubic feet in 1967 to 5.0 trillion cubic feet in 1975, or by 3.2 trillion cubic feet. Thus, by 1975 the OCS will account for about 20 percent of domestic production, up from about 10 percent in 1967. On an incremental basis production in the OCS would account for over 50 percent of the increase in production over the next 8 years.

There are two reasons for this very substantial increase in gas production forecast for the Outer Continental Shelf. First, a considerable portion of the proved reserves in the Louisiana portion of the Gulf of Mexico, while under contract, is not yet being withdrawn at rates of take permitted by the contracts or even in any substantial amounts. Second, assuming the necessary exploration and well drilling incentive, annual average reserve additions of natural gas from the Outer Continental Shelf, primarily the Gulf of Mexico, are expected to demonstrate a continued strong growth over the forecast period, from about 5.6 trillion cubic feet in 1967 to about 8.1 trillion cubic feet by 1975. This is a substantially larger growth rate than additions onshore, which are projected to be 16.9 trillion cubic feet by 1975, up from 15.3 trillion cubic feet in 1967. (page 129)

On a cumulative basis, approximately 52 trillion cubic feet of new reserves are projected to be found in the Outer Continental Shelf over the period 1968-1975, compared with 134 trillion cubic feet of new supplies to be found onshore. It is estimated that approximately 95 percent of the Outer Continental Shelf new supplies will come from the Gulf of Mexico, with the remainder from the California OCS.

The method used for estimating onshore and OCS new supplies stems from the Gompertz curve technique described above. Reserve additions were first projected by this technique for the United States including and excluding the Outer Continental Shelf. Therefore, the OCS supplies are derived by difference. However, the reserve additions derived by reference to the Gompertz technique are lower than reserve additions used in this study, which were in line with the Department of Interior projections. Thus, a further adjustment was required to compensate for the difference between these two levels of projected reserve additions.[1] The total new reserves in the OCS were allocated between the Gulf of Mexico and the California OCS on a basis reflecting the "potential" reserves in the two areas. By use of these techniques annual reserve additions in the Gulf of Mexico are projected to increase from 5.6 trillion cubic feet in 1967 to 7.7 trillion cubic feet by 1975, with cumulative reserve additions amounting to 49.7 trillion cubic feet over that period. Reserve additions in the California OCS are projected to average 300 to 400 billion cubic feet per year over the period.

The build up in OCS production, then, results from an interplay between proved reserves, annual reserve additions, and regional requirements. The Gulf of Mexico will be required to increase production in a substantial degree in order to help meet increasing requirements on the East Coast, in the Midwest, and of importance, in the local (Gulf Coast) industrial markets. All available production on the California OCS is expected to be absorbed by local markets.

To meet these requirements, annual production is projected to increase in the Gulf of Mexico from 1.8 trillion cubic feet in 1967 to 4.8 trillion cubic feet by 1975. Production in the California OCS was projected to be about 200 billion cubic feet in the final year of this period.

By 1975, the reserve-production ratio for the OCS areas will be slightly over 12 years, coinciding with the terminal year of the first phase of projected gas supplies for the Nation.

V. Projected Supplies of Natural Gas Available to Meet Domestic Requirements from 1976 to 1985

On the basis of probable supply-demand trends and minimum inventory requirements, the second phase of the projected supply and demand for natural gas commences on or about 1976. This turning point is crucial to the industry because annual reserve additions must reach and sustain substantially higher levels, even with the aid of increasing supplemental sources of gas, in order to meet annual increments of increasing demand but yet maintaining minimum inventory requirements. The analysis suggests that a substantial portion of these domestic supplies must

[1] Of the difference, 50 percent was attributed to the OCS. This percentage reflects the "potential" reserve analysis set out above.

come from the Outer Continental Shelf, if in fact these reserves prove to be within economical and technical reach.

To accomplish these ends, annual reserve additions, excluding Alaska, must increase on the average at 4.2 percent per year, or almost twice the growth rate of reserve additions in the earlier period. On this basis, reserve additions would amount to 37.6 trillion cubic feet by 1985 compared with 25.0 trillion cubic feet in 1975. (See page 128.)

If these higher reserve addition levels are attainable, then domestic proved reserves could support production of 30.8 trillion cubic feet by 1985, compared with 24.6 trillion cubic feet in 1975, and still maintain the minimum gas inventory requirement of 12 years. (See page 130) These projections are summarized as follows:

	TCF
1. Remaining to be discovered, circa 12/31/66 –	1,300
2. Less proved reserve additions:	
a. Estimated for period 1968-1975–	186
b. Estimated for period 1976-1985–	350
3. Remaining, circa 12/31/85–	764

While it may ultimately be demonstrated that not all of these reserves are economically recoverable, it is apparent that there is a wide margin for estimation error in either direction, not only to 1985 but well beyond.[1]

A. The Outer Continental Shelf Supplies of Natural Gas from 1976 to 1985

During the period 1968 to 1975 OCS gas production was projected to increase from 1.8 trillion cubic feet to 5.0 trillion cubic feet. This production is projected to more than double again by 1985, reaching 11.6 trillion cubic feet in that year, one-third of total gas requirements in the United States, and 38 percent of projected domestic gas production (exclusive of what may be production of gas in Alaska). That this increase of OCS gas production is a vital factor is made clear by the fact that domestic onshore production is projected to remain virtually constant after 1975 at approximately 19 to 19.5 trillion cubic feet, and could even decline over that period. (page 130)

The basis for these onshore and OCS projections is a continued application of the Gompertz curve technique modified as described above. By this

Projection of Domestic Reserves and Production, 1985 Compared with 1975 and 1967

Year	Reserves	Production	Reserve-Production Ratio
	(Trillion Cubic Feet)		
1967	289.3	18.4	15.7
1975	300.4	24.6	12.2
1985	369.0	30.8	12.0

The projection of domestic supplies of natural gas reaching these relatively large levels is based on several assumptions. First, it is apparent that a very considerable lead will be required for the industry to build up exploration, drilling, and production activities to requisite levels. This lead time could amount to as much as 6 years and perhaps more where production will be required from new producing areas, especially in the OCS. On this basis preliminary exploration should commence about 1969 or 1970 in such areas. Implicity paired with this lead time requirement is the assumption that sufficient incentive will be provided to commence and sustain the necessary exploration activity. A further assumption is, of course, that sufficient quantities of commercial reserves will be proved-up by drilling activities. Estimates of remaining economically recoverable reserves as reviewed above indicate that these supplies will be available.

[1] However, it should be noted that the above reserve estimates include Alaskan reserves in some unknown amount. The possible disposition of these reserves will be discussed in a succeeding part of this section.

technique annual new supplies in the OCS are projected to be in the proximity of 19 to 20 trillion cubic feet by 1985, exceeding by more than a trillion cubic feet the normalized annual new supplies of gas onshore. The inner working of supply and demand in the OCS may, therefore, be projected to 1985, compared with 1975 and 1967 as follows:

Atlantic OCS and, therefore, at this time there is no basis to confirm the potentiality of these supplies. From both a marketing and supply point of view, considering time lags involved in exploration and drilling, it would seem desirable that an exploration program be under way in the near future to test the potential and gradually define the supply parameters of the Atlantic OCS, so that a reasonable estimate of supplies can realistically be made by 1972 or 1973.

Projection of OCS Reserves and Production 1985 Compared with 1975 and 1967

Year	Reserves (Trillion Cubic Feet)	Production (Trillion Cubic Feet)	Reserve-Production Ratio
1967	34.2	1.8	19.0
1975	59.9	5.0	12.0
1985	138.6	11.6	12.0

Projection of these OCS supplies by location becomes quite difficult after 1975. Trending techniques would continue to project the lion's share to come from the Gulf of Mexico with a lesser portion attributed to the California OCS. This is confirmed in degree by estimates of recoverable reserves within economic and technical reach, out to 200 meters on the Outer Continental Shelf (page 127). These estimates also indicate that the Atlantic OCS may contain gas reserves at approximately two-thirds of the level for the Gulf of Mexico. The Geological Survey view regarding the Atlantic OCS potential is confirmed, with guarded optimism, by others.[1] Yet no wells have been drilled on the

Without knowledge of in-fact gas supplies on the Atlantic OCS, an illustrative and rather modest production of gas is assumed to commence in the Atlantic about 1976, and by 1985 production is assumed to be approximately 1.5 trillion cubic feet. Thus, the Atlantic OCS is projected to account for approximately 13 percent of the total OCS production in 1985, compared with 83 percent from the Gulf of Mexico and 4 percent from the Pacific OCS. The regional OCS supplies projected to 1985 may thus be summarized:

Projection of OCS Reserves and Production 1985 Compared with 1975 and 1967 (Trillion Cubic Feet)

	Gulf of Mexico		California OCS		Atlantic OCS	
	Reserves	Production	Reserves	Production	Reserves	Production
1967	34.2	1.8	0	0	0	0
1975	58.2	4.8	1.7	0.2	0	0
1985	116.1	9.6	6.1	0.5	16.4	1.5

The cumulative reserve additions can also be compared with estimated remaining economically recoverable reserves, circa 1967:

[1] For example, see "Oil and Gas Extraction Technology" by T. D. Barrow, Director, Humble Oil and Refining, before the Mineral Resources of the World Ocean Symposium, Newport, Rhode Island, July 12, 1968; and "Exploring Offshore Megalopolis," by P. T. Fowler, Exploration Surveys, Inc., Dallas, Texas, 1968.

Additions of Estimated Economically Recoverable Reserves To Water Depths of 200 Meters in OCS Areas
(Trillion Cubic Feet)

	Gulf of Mexico	Pacific	Atlantic	Alaskan
1. Remaining to be discovered, circa 12/66 1/	180	27	148	190
2. Less: proved reserve additions:				
a. Estimated for period 1968-1975	50	3	0	*
b. Estimated for period 1976-1985	132	8	25	*
3. Remaining to be discovered, circa 12/85	**	16	123	*

1/ Estimates as set out on Table B-9 arbitrarily discounted by 30 percent as a compromise with other, more conservative estimates; the Gulf of Mexico, out to 200 meters of water depth, would be depleted by 1985.

* Not estimated

** Remaining reserves in the Gulf of Mexico would primarily be beyond 200 meters. They are not estimated.

It should be emphasized that these levels of projected supply between the several Shelf areas are necessarily illustrative and speculative. It is reasonable to assume that both Atlantic and Pacific OCS production will be the most economic supply for "local" markets compared with any and all alternative sources of gas. Therefore, if new supplies of natural gas from these Shelf areas exceed the above estimates, especially the Atlantic OCS with its unknown potential, it is reasonable to assume that the enhanced supplies will support higher production levels which, in turn, will "displace" other projected supplies of natural gas flowing to both the East and West Coasts.

It is noted that the above estimates of economically recoverable reserves attribute very substantial potentials to the Alaskan OCS. In addition, natural gas supplies have been found onshore Alaska and more of these supplies presumably will be added in the future, concomitant with the drilling for petroleum.[1] For example, it would be reasonable to assume that supplies of natural gas will be found as part of the North Slope play.[2] Part of the natural gas supplies in Alaska will, of course, be consumed in local Alaskan markets, but these demands are insignificant when compared with potential reserve estimates. Presumably gas will continue to be liquefied and transported in increasing quantities to Japan. Initial shipments from the Cook Inlet to Japan are scheduled to commence in 1969, but again, in relatively small volumes. Therefore, the major market for these potential gas reserves will be the mainland of the United States. However, the possibility of shipping liquefied natural gas from Alaska to the West Coast U. S. mainland is seriously affected by the fact that these supplies will not be competitive with other domestic supplies. A competitive disadvantage aggravated by legal requirements that intercoastal transportation between points on U. S. soil be carried on by U. S. built ships flying the U. S. Flag of Registry. There is no basis at this time to predict that LNG shipments from Alaska to the U. S. mainland will be exempt from these requirements. Therefore, little or no LNG shipments of Alaskan gas are projected for mainland consumption up to the year 1985.

[1] As of December 31, 1967 proved reserves of natural gas in Alaska were estimated by the American Gas Association at 3.6 trillion cubic feet.

[2] It is noted that the Prudhoe Bay field was announced as an *oil and gas* discovery. See Chapter C of this report.

B. Supplemental Sources of Natural Gas from 1976 to 1985

As set out above, domestic production by 1985 is projected at 30.8 trillion cubic feet, or 88.5 percent of domestic requirements which amounts to 34.8 trillion cubic feet. This represents a declining trend, in that domestic production is projected to fulfill

95.3 percent of requirements in 1975. The remainder of the 1975 requirements will be met by overland imports, primarily from Canada in the amount of 1.2 trillion cubic feet. In 1985, however, the domestic deficiency will amount to some 4 trillion cubic feet, and our study of future Canadian supplies indicates that only 1.5 to 2.0 trillion cubic feet will be available for exports after fulfilling Canadian domestic requirements.

The northern Canadian supply structure, like Alaska, is very uncertain at this time, and these estimates could be revised upward if the northern potential is realized.[1] This optimistic note does suggest that net overland imports from Canada and Mexico be set at 2.0 trillion cubic feet in 1985, leaving another 2 trillion cubic feet of the domestic deficiency to be fulfilled from other sources.

There are several possibilities for supplying this supplemental gas. First, and most desirable, this remaining supplementation could come as a result of an accelerated exploration and development program from what is assumed to be a prolific Atlantic OCS. Certainly if Atlantic OCS reserves are capable of producing an additional 2 trillion cubic feet per year, over and above the 1.5 trillion assumed as of 1985, this supply will find an East Coast market since the East Coast generally experiences a higher cost of energy. Thus, the Atlantic OCS could fulfill the remaining supply gap by 1985.

If domestic supplies (excluding Alaska) as supplemented by Canadian imports fail to materialize to the extent thus projected, then the Nation must look to some combination of several other sources: (1) gas shipped from Alaska, either in gaseous form by pipeline or in a liquid form by either pipeline or tanker, (2) gas manufactured from domestic coal reserves, or (3) LNG imports.

As a general proposition, a resource in its natural form is the most economical form of energy (if it is available in sufficient commercial quantities) because of inefficiencies in form conversion. Thus, it is estimated that 44 percent of the Btu content of coal could be lost in its conversion to pipeline quality gas.[2] This becomes a problem of the most efficient use of alternative energy supplies. However, if government and industry continued to seek commercial development of gas from coal, perhaps to gain experience and provide an "insurance policy" against indigenous natural gas supply shortages, it is possible that this source could provide some modest supplementation by 1985. However, the inherent lead time in moving from bench scale or pilot plant (with the absence of proven cost estimates) to commercial operations requiring very substantial capital investments suggests this possible source of gas supplementation will not become important until beyond 1985.

On the other hand, LNG is now a commercial reality in other parts of the world, imported primarily by energy deficient countries. While technological improvement may reduce estimated costs of delivering this form of gas to the United States, it is not presently competitive with indigenous sources of natural gas.[3] Furthermore some consideration must also be given to the reliability of natural gas produced in a foreign country and transported by tanker before reaching points of consumption in the United States.

In summary, it is possible that LNG will, on a selected basis, be imported into the United States by 1985 and thereby provide a further modest

[1] *See Petroleum Press Service*, February 1969, pp. 63-64.

[2] "There would be an increase in total energy requirements due to the inefficiencies in converting coal to gas, very conservatively estimated at 56 percent (or 70 tons of coal per million cubic feet of 1,032 Btu per cubic foot pipeline gas). The reason for this relatively low efficiency value is that no credit for by product fuels and energy is taken. "H. R. Linden, "Sources of U.S. Gas Supply – 1968 to 2000." A paper presented before the Natural Gas Men of Houston, December 10, 1968.

[3] An interesting comment on these matters was recently expressed by the president of Northern Illinois Gas Company:

"Unfortunately, it may be dangerous to wait and see. There is an unavoidable and significant time lag between the time that the exploration bit enters the ground and the time that an incremental supply of gas is available for delivery to consumers. Furthermore, if stable and inadequate area prices should inhibit exploration, and deteriorate the industry's supply situation, a second adverse circumstance would occur simultaneously. Stable low prices for natural gas would maintain the present substantial price differentials between naturally occurring methane and synthetic methane from coal or oil shale, or massive imports of liquefied natural gas. Thus the economic penalty on these unconventional sources would not be lessened, and their advent (which is inevitable at some future date), as well as the necessary prerequisites of further technical research, might be delayed. As a result, the continuous economic price balancing of supply and demand could lead to abnormal and unnecessarily large demand reductions in the face of fixed prices and inadequate supplies, rather than the more preferable compromising of modest demand decreases and modest price increases." Marvin C. Chandler, "Impact of Area Pricing on Production and Demand," *Public Utilities Fortnightly*, October 10, 1968, page 76.

supplementation to indigenous supplies.[1,2]

There remains the very substantial Alaskan potential which will be discussed in the next section.

C. The Outer Continental Shelf Role in Supplying Natural Gas Beyond 1985

Pieces of the supply puzzle beyond 1985 to the year 2000 have been shaped in previous sections of this Chapter. The uncertainty at these far-out dates is so great as to preclude any suggestion of precision in estimated, projected, or extrapolated reserve additions, production or proved reserves. However, a broad-gauged analysis will be useful in providing an understanding as to the general direction of supply sources.

Natural gas requirements are projected from 33 trillion cubic feet in 1985 to 42 trillion by the year 2000, a projection which assumes no major shifts in the national energy mix. If it is assumed that the share supplied from indigenous sources will decline to 80 percent of total requirements, then domestic production would be about 34 trillion cubic feet in the year 2000 compared with 31 trillion cubic feet in 1985. The remaining 20 percent presumably would be met by some combination of imports, both pipeline and tanker, and in come degree by the manufacturing of gas from coal.

On the basis of these assumptions, some 510 trillion cubic feet of new reserves will have to be proved-up between 1985 and 2,000, to sustain domestic production at minimum inventory levels. Cumulative production over this 15-year period will amount to about 445 trillion cubic feet. Finding new supplies of this magnitude is a most substantial assignment considering that incremental costs of these supplies must remain competitive with other energy resources.

Yet the evidence indicates that substantial economically recoverable natural gas reserves will still be available in the United States by 1985.

Comparing potential reserves and new reserve requirements, it would seem from the above tabulation that our resources are capable of meeting the assumed supply objective by the year 2000, and perhaps beyond that year. Evidence also indicates that OCS will supply about 43 percent of these resources, but attaining this level implies substantial production from the Atlantic OCS. In the Gulf of Mexico it would seem that any substantial growth of supplies beyond 1985 will necessitate drilling beyond 200 meters, which is not unreasonable. Onshore supplies might also be expanded beyond present estimates by deeper drilling and nuclear stimulation.

Estimate of Potentially Economically Recoverable Reserves, 1985 Compared with 1966

(Trillion Cubic Feet)

	Total U. S.	O C S[1/]	Remainder of U. S.
1966	1,300	545	755
Less: Reserve Additions 1967 - 1985	536	218	318
Net: 1985	764	327	437

1/ Out to water depths of 200 meters.

[1] "To some extent the use of LNG will enable energy-short countries to correct their supply/demand inbalances, but it appears now, because of the tremendous cost involved, that LNG will not be able to compete with indigenous gas in any nation having adequate natural gas supplies . . . All of these considerations lead us to believe that LNG will come to the U.S. only if there is a gas supply shortage." W. J. Greenwald, "Growing Importance of Natural Gas in Foreign Operations," A Talk to the Houston Chapter of the API, October 29, 1968. Also see "Imports Complement Domestic LNG," by deFroundeville, Jensen, and Wulff, *Pipeline Industry*, October 1968.

[2] The regional model sheds light on where supplemental sources might be consumed in 1985. LNG would be imported only by the East Coast markets. Gas from coal would be consumed primarily by the Appalachian market region, which encompasses very large coal reserves, and by the Northern Plains market region from a plant using low-cost lignite reserves found in the region. A hypothetical plant located in Southern Illinois was shown to supply only a limited market in the Great Lakes region, not sufficient to justify a medium-sized coal gasification plant. Overland imports from Canada go primarily to the Pacific Northwest, Pacific Southwest, and Great Lakes market regions. These flows are shown in more detail in Appendix 3.

Yet there is a "hitch" in this analysis. A most substantial portion of the economically recoverable reserves estimated to be potentially available in 1985 are located in Alaska, including the Alaskan OCS.[1] As set out above, these supplies have not been fitted into the supply-demand models through 1985. Beyond 1985 Alaskan supplies could be vital to the mainland. The Alaskan OCS alone is estimated to have a potential of some 200 trillion cubic feet of economically recoverable reserves.

Therefore, about the year 1985, the United States will be ready to absorb Alaskan natural gas moving in very large volumes over long distances to the mainland. Based on current economics, this type of movement must be primarily by pipeline in gaseous or liquid form, perhaps in extra large diameter pipe.[2,3] The technological research necessary to bring about the economies attending this large volume movement through extra large diameter pipe is deserving of immediate attention by both government and industry.

VI. Summary of Findings

The summary of the projected supply and demand for natural gas in the United States is set out on pages 128, 129 and 130.

With annual reserve additions of natural gas increasing at a rate of approximately 2.2 percent per year, indigenous supplies should prove capable of meeting probable requirements until about 1975; but after 1975 an increased finding rate with a modest continuation of supply supplementation from other sources will be required in order to maintain a 12-year reserve-production ratio which is considered to represent the minimum national inventory requirement. Therefore, 1975 will mark the end of the first "supply phase" and 1976 will begin the second phase of the projected supply and demand of natural gas.

In 1975 domestic production would be approximately 24.6 trillion cubic feet, or 95.3 percent of the requirements, with the balance primarily being provided by overland imports of Canadian gas. With respect to the domestic production, some 5 trillion cubic feet, or about 20 percent, is expected to be withdrawn from the Outer Continental Shelf reserves.

Over the period 1975 to 1985 a modest increase in supplementation is expected to come from a combination of overland imports, liquefied natural gas imported by tanker and synthetic gas manufactured from domestic coal, amounting in the composite to about 4 trillion cubic feet, or 11 percent of total domestic requirement by 1985. Domestic supplies are expected to produce the remaining 30.8 trillion cubic feet of gas, of which almost 38 percent is projected to be produced from the Outer Continental Shelf reserves. While the Gulf of Mexico will continue to dominate OCS production, it is estimated that supplies from the Atlantic OCS will be required after 1975. Supplies will not be available from the Atlantic OCS in significant quantities by 1976, however, unless an exploratory program is under way in the near future to test that supply potential.

Over the period 1985 to 2000, supplementation in the form of gas from coal and imports may account for 20 percent of domestic requirements. Production from indigenous reserves will supply at least 80 percent of gas demands, based on estimates of our resource base, with at least 40 percent of this domestic production coming from OCS reserves, if the estimated Atlantic OCS potential exists and is developed in time. To realize these levels of domestic supplies, however, will require that very substantial volumes be shipped from Alaska to the mainland.

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[1] In fact, some unknown portion of the Alaskan gas reserves undoubtedly will have been proved by 1985.

[2] A portion of these natural gas supplies from Alaska to the mainland could move also in liquid form by tanker, if economic and legal modifications can be affected to reduce the cost of intercoastal shipment of LNG in the United States.

[3] While 42 inch diameter pipe is considered large for long distance gas transmission in the United States at this time, other parts of the world are examining the economics which might result from using pipe up to 100 inches in diameter. "It has since been indicated that pipes of up to nearly 100 inches diameter will be used in Siberia in the early 1970's . . ." *Petroleum Press Service*, May 1968, page 169.

CHAPTER C
PETROLEUM SUPPLY AND DEMAND[1]

I. Introduction

Events in the year 1968 have created a new dynamic outlook for the United States petroleum industry. Until July 18, 1968, many authorities, from government and industry, continued to forecast in varying degree an impending "energy gap" occurring on or about 1975 when indigenous supplies of petroleum would be insufficient to meet the growing demand and, therefore, our country would henceforth have to obtain its supplies increasingly from some combination of oil shale, tar sands, synthetic petroleum manufactured from coal, and enlarged imports of petroleum from foreign countries.

On July 18, 1968 the initial discovery of the Alaskan North Slope was announced as "potentially one of the largest petroleum accumulations known to the world today." [2]

Since that announcement, increased anticipation of the North Slope potential has built up as company after company has acquired acreage and established drilling programs for the winter of 1968-1969. The contagious optimism of the "largest petroleum accumulations known to the world today" has spilled over from the Prudhoe Bay field to the whole of the North Slope, into the Canadian-MacKenzie River Delta area, up to the Arctic Islands, and southward into the Gulf of Alaska.[3]

Thus, there is a momentum of anticipation (or hope) that the center of gravity of North America crude oil production will eventually shift to the far North, impacting on the international supply-demand structures for petroleum and placing into abeyance for an indefinite period of time the previously anticipated pending energy gap.[4]

It is within this framework of almost universal optimism, but with no certainty, that supply and demand projections for the United States will be constructed in this Chapter, oriented to the likely role to be played by supplies in the Gulf of Mexico, the Pacific OCS, the Gulf of Alaska, and the Atlantic OCS.

II. Petroleum Supply and Demands Trends, 1951-1967

In this section is provided a statistical review of important trends in petroleum supply and demand from 1951 through the year 1967. Emphasis is placed on those elements of supply which bear importantly on the demand (requirements) for crude oil, primarily as a feedstock for petroleum refineries, as distinguished from market characteristics and trends of individual petroleum products.

A. A Review of National Supply and Demand

Page 131 statistically reviews the key elements of supply and demand for the total United States. Domestic product demand, which was slightly over 7,000 MBD (thousand barrels per day) in 1951 has increased steadily over the period, at a rate of 3.9 percent per year, and in 1967 reached a level of 12,560 MBD. In more recent years product demand has been somewhat above this growth rate, mainly as a result of the accelerated business expansion since 1961.[5]

Crude oil, of course, is the primary source in supplying this demand. However, increasing notice must be taken of three other elements of supply—(1) natural gas liquids, (2) product imports, and (3) "refinery gain," the technological contribution of providing more refinery product output, on a volume basis, than the liquid inputs at the refinery still. A careful review of page 131 shows that these supply elements have displaced crude oil at an accelerating pace since 1951.

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[1] Petroleum is defined to include crude oil, natural gas liquids, and products derived from these hydrocarbons.

[2] Atlantic Richfield press release regarding Prudhoe Bay: "Atlantic Richfield—Humble Arctic Slope discovery termed one of world's largest," Philadelphia, 1968. Among other things the press release stated "DeGolyer and McNaughton, Dallas, said—In our opinion, this important discovery could develop into a field with recoverable reserves of some 5 to 10 billion barrels of oil, which would rate it as one of the largest petroleum accumulations known to the world today."

[3] For a concise review and description of petroleum exploration in the Arctic region, see "Arctic Oil May Bridge Supply Gap," and other articles in *Oilweek*, September 30, 1968, pp. 34-57.

[4] "If Atlantic Richfield and Humble's North Slope discovery lives up to expectations, it could delay by 5 or 6 years the need for synthetic fuels. And if three or four additional fields are discovered on the Slope, the entry of synthetic fuels could be delayed as long as 15 years," remarks attributed to M.A. Wright, Chairman of the Board, Humble Oil and Refining Company, *The Oil and Gas Journal*, October 21, 1968, p. 50.

[5] Preliminary estimates place domestic demand for petroleum in 1968 at 13,300 MBD, a rise of 5.9 percent above 1967. API Press Release, December 30, 1968.

Natural gas liquids production in 1951 was only 561 MBD, concentrated largely in a few producing areas of the Southwest. By 1962 production had reached above the level of 1,000 MBD, and by 1967 over 1,400 MBD. In the latter year approximately 11 percent of product demand could be accounted for by NGL plant liquids. This expansion in output was due in part to the attractiveness of certain of these liquids, particularly butanes, as a blend in making gasolines, the chief product in petroleum demand.

The rise of product imports has been an even more dramatic development on the supply side. As a result of their marginal economics, domestic refiners have increasingly reduced residual fuel oil yields, upgrading this portion of the barrel to higher-valued products. As a consequence, heavy fuel oil has been imported to fulfill market requirements. In 1967 net product imports, primarily residual fuel oil, amounted to 1,175 MBD, up from only 11 MBD in 1951 and 607 MBD in 1960.

Grouped together with refinery gain on page 131 are various miscellaneous supply sources which, by themselves, are relatively insignificant on a national scale, but necessary to obtain a supply balance. These include unfinished oil rerun to refineries, stock changes, and crude losses. Since 1958, these statistical quantities have amounted to about 1 to 2 percent of supply. As will be discussed later, refinery gain is expected to be much more of an influence on supply requirements in the future.

As a result of these supply alternatives, growth in domestic crude oil requirements has not kept pace with increases in product demand. Compared to an average rate of growth of 3.9 percent for product demand from 1951 to 1967, crude oil requirements increased on the average by only 2.6 percent per year. In 1967 crude oil requirements were equal to 79 percent of demand, whereas in 1951 they accounted for 95 percent.

Further restriction on the expansion of domestic crude oil production has been the growing level of imported crude oil. Between 1951 and 1957 the volume of these imports doubled to about 1,000 MBD. Since that time there has been only a very slow increase in these imports (as a result of both the voluntary and mandatory control programs). In 1967, for instance, imports of 1,128 MBD were only 100 MBD or less than 10 percent above the year a decade ago. Clearly, the import program has been successful in preventing a serious deterioration of the market for domestic crude oil.

It should be observed from page 131 that whereas domestic crude production was essentially on a plateau between 1956 and 1961, since that time production has risen considerably and consistently. In 1967 domestic crude oil production of 8,810 MBD was equal to 89 percent of total crude oil requirements. Between 1961 and 1967 the demand (requirements) for crude oil in the United States grew by 1,710 MBD. During the same period domestic crude oil production increased by only a slightly lesser amount—1,627 MBD.

On page 131 a further breakdown of national crude oil production is given for lease condensate, as well as the amount of crude oil produced in the OCS portion of the Gulf of Mexico in contrast with onshore areas.

Lease condensate, or the volume of liquids recovered from associated or non-associated gas in gas separators or field facilities, represents a statistical problem because it is classified as crude oil by the Bureau of Mines, while it is included in natural gas liquids by the API. The numbers are shown here to illustrate their magnitude to crude oil production. In 1967 aggregate lease condensate in the United States was 356 MBD, or about 4 percent of total production.

The statistics of offshore (OCS) domestic net production as compared to onshore areas show several interesting contrasts. Offshore net production since 1951 captured an increasing and significant share of of incremental crude oil requirements. This is particularly noticeable during the period after 1961. From this date through 1967, slightly over 30 percent of the increase in domestic production has come from the OCS. In contrast, onshore areas have experienced only a relatively small increase in production level since 1951. Net production in that year was approximately 6,000 MBD. Not until 1965 did the quantity of net production from onshore areas rise above 7,000 MBD. During the same 14-year period, while onshore net production increased by only 1,000 MBD, product demand was growing by 4,500 MBD.

B. Regional Supply and Demand Review

Within the broad sweep of the national supply and demand trends there are important variances on a regional basis. It is, therefore, necessary to look past the statistical record of petroleum supply and demand at the national level to the trends within the country's several regions, usually classified under the designation PAD Districts. Some of these Districts have excess supply available, others are deficient. Some Districts are geographically suited to receive

overseas imports, others are essentially inland. Some Districts are centers of refining capacity in excess of local product requirements, others require transportation of petroleum products in lieu of local processing. The following review highlights the statistical record of supply and demand by Districts with pertinent comments on trends since 1955.

PAD Districts I and II

The predominant consuming area of the Nation for petroleum products is PAD Districts I and II, covering the East Coast, Middle West, and Mid-Continent States. Almost two-thirds of the Nation's use of petroleum products takes place within this area, amounting to 8,579 MBD in 1967. (See page 132.) Since 1955, product demand has shown a growth rate of 3.3 percent per year, slightly below the national performance.

Local supplies have been able to contribute only a small portion of this demand and the deficiency has been widening through the years. In 1955 the production of crude oil in these two Districts, 1,328 MBD, was the equivalent of only 23 percent of product demand. In 1967 production remained at the same level, but the proportion to demand had dropped to 16 percent. The conclusion is clear that where the Nation's demand for petroleum is the greatest, local supplies have not increased with the result that growing quantities of oil are needed from other Districts and foreign areas.

To supply this increasing deficit, both crude oil and petroleum products have been supplied to Districts I and II in growing volume. Product imports since 1955 have tripled and in 1967 amounted to 1,242 MBD. Shipments of products from other Districts, particularly District III, increased during the same period by almost 1,000 MBD to reach 2,901 MBD in 1967. Crude oil shipments from other Districts have grown more modestly, increasing from 1,381 MBD in 1955 to 2,038 MBD in 1967. Imports of crude oil have remained essentially constant since 1960.

In review, the historical record of supply and demand in Districts I and II shows an increasing deficit in local supply. This deficit to date has been relieved by a growing inflow of foreign and domestic products, and to a lesser extent, through additional movement of crude oil from domestic sources. For the future it appears that this area holds the key to substantial incremental gains of markets for both the traditional surplus regions within the country, as well as potential new sources of supply, such as the North Slope and the Atlantic OCS.

PAD District III

In contrast to Districts I and II, there is a growing surplus of both crude oil and petroleum products in District III, the Southwest, over local requirements, as set out on page 133. Product demand in 1967 of 1,878 MBD represented only 15 percent of the national total and is growing at an average of 3.3 percent per year, the same as in Districts I and II.

Crude oil and natural gas liquid production, on the other hand, amounted to 6,842 MBD in 1967, or over three times District product demand. As a result, the bulk of this supply moves to other regions in the form of both crude oil and products.

Particular notice should be given to the rise of NGL production in District III, which nearly doubled in volume between 1955 and 1967 (a growth rate averaging 5.8 percent per year). Crude oil production, on the other hand, increased during the same period by 3.0 percent per year.

An important observation of these historical statistics is the fact that a growing proportion of the surplus of supply is being shipped in the form of products as opposed to crude oil. Since 1955 products shipments from District III have increased by some 1,100 MBD; crude oil shipments by less than 700 MBD. Continued expansion of refining capacity in the area has been the prime factor in this trend.

Thus, District III represents the major producing area in the United States, accounting in 1967 for two-thirds of domestic crude oil production and three-fourths of domestic natural gas liquids production, with an increasing portion of these production streams coming from the Gulf of Mexico.

PAD District IV

Data on this region, the Rocky Mountains, is set out on page 134. This region is the smallest of the four regions studied both in terms of product demand and crude oil requirements. Product demand in 1967 totaled 354 MBD, equal to some 3 percent of total U.S. demand. Since 1955 product demand has grown at an average annual rate of 2.6 percent per year.

From a supply standpoint the area is similar to PAD III, only in that it produces more crude oil than it consumes. Because of limited refinery capacity in the region, this surplus is shipped primarily to PAD II. In 1967 total crude oil production amounted to 628 MBD, compared to the District's product demand of 354 MBD. Crude oil shipments to other regions totaled 304 MBD. Since 1961 both crude oil production, and in turn shipments to other areas, have been on the decline. An upturn has occurred in 1968 as a consequence of several significant

discoveries which are the basis for projecting the Rocky Mountains as a surplus producing area over the forecast period, without regard to the region's oil shale potential.

PAD District V

Data on this region, which besides the West Coast includes Alaska and Hawaii, is set out on page 135. On balance, District V has been a net importer of both crude oil and products, reflecting the inability of local production to meet the region's demand for products.

Product demand in 1967 averaged some 1,700 MBD, up from 1,100 MBD in 1955, an average annual growth rate of almost 4 percent per year.

NGL production has been relatively small, averaging only 64 MBD in 1967, and accounting for slightly less than 4 percent of demand. Net product imports and shipments from other regions accounted for 11 percent of product demand in 1967. The bulk of these shipments was supplied by PAD Districts III and IV.

Crude oil requirements in 1967 averaged 1,482 MBD, of which 1,073 MBD was supplied by local production. For the most part, local crude oil production remained fairly level from 1960 to 1965, but then increased sharply in 1966 and 1967 because of Alaskan discoveries as well as additional supplies in California, due in large part from secondary recovery of heavy oil fields. Crude oil imports since 1965 have declined because of this increase in local supplies, reversing the post-war trend.

All indications point to the conclusion that District V will reverse its historical deficit supply and prospectively become a surplus producing area. The extent and timing of this transition will depend on the advent of major producing areas being developed in District V, such as the North Slope of Alaska, the Gulf of Alaska, and the California OCS.

The above statistical description of historical supply and demand of petroleum lays out one means for the projections of succeeding sections. Trends in domestic petroleum reserves represent another major input factor in assaying future events, and these reserve trends will be set out in the subsequent section. Before proceeding with this section, however, it is necessary to briefly touch on yet a third important factor, the imports of petroleum.

C. Petroleum Imports

Undoubtedly the most controversial aspect for the domestic petroleum industry has been, and will probably continue to be, the Mandatory Oil Import Program. While it is beyond the scope of this contract to analyze in depth the import program, it is nevertheless informative to highlight some of the past record in order to place in perspective the question of the future level and impact of imports on domestic supply sources.

As presently constituted, imports of petroleum (crude oil, unfinished oils, and products other than residual fuel oil used as fuel) are limited to quantities subject to governmental determination. Since any change in policies is beyond the realm of prediction, this report assumes no significant change in governmental policy.

Future developments would appear to hinge on the necessity of maintaining a viable domestic industry, subject to a continuing threat to national security, balanced against the lower cost of crude oil from foreign countries. The international political situation would indicate no lessening of tensions abroad. Thus, it is clear that from the viewpoint of national security interest, it will be necessary to continue limitation of imports.

In light of these considerations, future forecasts of imports in this report will be based on the same assumption adopted by the U.S. Department of Interior in their study entitled "United States Petroleum Through 1980."[1] The assumption made by Interior was that the total level of imports will continue in the range of 20 percent of total supply at a national level.

The basis of the assumption that 20 percent of future supply will come from imports is illustrated historically on page 136. Since 1961 the ratio of all petroleum imports to total new supply (the sum of crude oil production, NGL production and imports) has ranged between 19 percent and 21.5 percent. This has occurred even though imports of residual fuel were increasing above previous, more stabilized levels, offset in degree by a disruption of foreign crude supply during the year 1967 and into 1968.

One factor which may affect the assumed 20 percent petroleum import level is the future increased in importation of residual fuel oil. The imports of fuel oil for all practical purposes are exempt from the mandatory program. The high demand elasticity of this product makes the prediction of future import increases dependent upon future inter-fuel price competition, the impact of sulfur content restrictions under air pollution control regulations, and the future availability of natural gas supplies.

The assumption that inports will remain at 20

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[1] Washington, D.C., July 1, 1968.

percent of supply over the forecast period is, of course, quite arbitrary. It should be pointed out, however, that if the potential of new producing areas such as the North Slope, the Gulf of Alaska, and the Atlantic OCS are realized in substantial commercial quantities over the forecast period, the maintenance of the 20 percent level could become difficult, if not impossible. It might be visualized that in such a case it would be more realistic to expect imports to be controlled on some other basis. On the other hand, if new domestic producing areas are not forthcoming in substantial magnitude, the limitation of imports might be equally difficult.

III. Trends in Domestic Petroleum Reserves, 1947-1967

A. Crude Oil

The trends in domestic supplies of crude oil in the United States since World War II essentially divide into two periods—the period from 1947 to 1956, and the period from 1957 through 1967, as detailed on pages 137, 138, 139, and 140.

From 1947 to 1956, well drilling activity and oil well completions increased annually, and as a result, annual new supplies (the summation of annual extension revisions and new discoveries) exceeded net production by about 44 percent. Total proved reserves, as reported by the American Petroleum Institute, increased from 21.5 billion barrels as of December 1947 to 30.4 billion barrels as of December 1956. Production also increased over this period from 1.9 billion barrels in 1947 to 2.6 billion barrels in 1956, the year of the first Suez crisis. The ratio of proved reserves to production fluctuated in a narrow range over this period from a postwar high of 13.6 in 1949 to a low of 11.6 in 1947 and 1948. In 1956 the ratio was 11.9.

Subsequent to 1956, well drilling activity has declined, annual new supplies on the average have barely exceeded production and total proved reserves have ranged narrowly between 30.3 and 31.8 billion barrels, amounting to 31.4 billion barrels as of December 1967. Crude oil production has continued to increase from 2.6 billion barrels in 1957 to 3.0 billion barrels in 1967, undoubtedly affected by the Middle East crisis in that year. In recent years, the proved reserves-to-production ratio has declined, from 12.9 years in 1958 to 10.3 years in 1967, the lowest ratio over the postwar period.

The preceding recitation of postwar trends relates to proved reserves in the United States as defined by the American Petroleum Institute. These proved reserves are the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. In general they include only the producible content of the explored portions of the reservoirs, and in the case of stimulated recovery projects, only those supplementary quantities of oil that may be produced by equipment actually installed, or which is judged producible on the basis of a successful test of a pilot project.[1] Thus, proved reserves represent underground assets in which the petroleum industry has made specific investments of capital.

Commencing in 1966, the American Petroleum Institute added another category of reserves termed "Indicated Additional Reserves From Known Reservoirs," which are considered "economically available by application of fluid injection, whether or not such a program is currently installed."[2] This is oil approaching the same economic value as that in proved reserves, the principal difference being that the investment in facilities to bring it into the latter category has not yet been made. The normal expectation is that in the future the necessary investments will be made, and the oil will then pass from the "indicated" category into the "proved" category.[3]

The "indicated" additional reserves from known reservoirs amounted to some 7.6 billion barrels as of December 1966 and as of December 1967. Thus, these additional reserves amount to approximately the equivalent of total annual new supplies of crude oil in the "proved" category for the years 1963, 1964, and 1965 in the composite. If the "indicated" reserves are added to the "proved" reserves, our domestic supplies are approximately 39 billion barrels as of December 1967, and the reserve-to-production ratio computed on that basis would amount to 12.8 in 1967, compared with 13.6 in 1966.[4]

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[1] *United States Petroleum Through 1980,* U.S. Department of Interior, Office of Oil and Gas, July 1968, at page 13.

[2] *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1966,* at page 24.

[3] *United States Petroleum Through 1980,* op. cit., at page 14.

[4] The Interstate Oil Compact Commission has an even broader concept for identifying additional quantities of oil in known deposits comparative with the American Petroleum Institute. As reported in *The Oil and Gas Compact Bulletin,* 1966, the Commission estimates additional oil economically producible by conventional fluid injection is approximately 17.5 billion barrels, or about 10 billion barrels more than the figure used by the American Petroleum Institute.

From a regional viewpoint District III, including the Gulf of Mexico, has continuously and increasingly dominated domestic supplies of crude oil in the United States over the postwar periods, as shown on pages 141, 142, and 143.[1] Production in District III increased from 1.5 billion barrels in 1956 to 1.9 billion in 1967. As a percent of total U.S. production, this accounted for about 64 percent in 1967, up from 59 percent in 1956. Over this same 10-year period, modest production increases were posted in Districts IV and V, while declines were experienced in Districts I and II.

Over half of the net increase in District III production has come from the Gulf of Mexico where crude oil production increased from 35 million barrels in 1956 to 256 million in 1967. Thus, by 1967 the Gulf accounted for 13.2 percent of District III production, up from 2.3 percent in 1956.

In support of these production levels, the API reports the bulk of proved reserves also to be in District III, amounting to 21.2 billion barrels in 1967, up from 20.0 billion in 1956. As a percent of total proved reserves in the United States, District III accounted for 68 percent in 1967 as compared with 66 percent in 1956. An increase in proved reserves also was experienced in District V, which now includes Alaska, but declines were experienced in Districts I, II, and IV.

In 1966 and 1967, indicated additional reserves from known reservoirs were also reported by the API, amounting in the latter year to 3,549 million barrels in District III, 2,796 million in District V (primarily California), 697 million in District II, 477 million in District IV, and 103 million in District I.

Clearly, these indicated reserves have had a most substantial impact in District V, amounting to 59 percent of proved reserves as of 1967, compared with 17 percent appreciation of total reported reserves in District III. The impact of these additional reserves can also be appreciated by reference to the reserve-production ratios. In District III, the reserve-production ratio was 13.3 years in 1956, declining to 11.1 years in 1967, when based on proved reserves. However, the 1967 reserve-production ratio was 12.9 in District III when based on the sum of proved and indicated reserves. In District V, the reserve-production ratio increased from 10.8 years in 1956 to 12.2 years in 1967, based on proved reserves. When indicated reserves are added to proved reserves, the 1967 reserve-production ratio becomes 19.4 years.

[1] See Appendix 5 for detailed identification of these trends by PAD District and principal producing states.

In net balance the Gulf of Mexico showed a greater increase in proved reserves than either District III or the total United States. Specifically, proved reserves in the Gulf of Mexico increased from 752 million barrels as of December 1956, to 2,375 million barrels as of December 1967, a net increase of 1,623 million barrels. By way of comparison, proved reserves in District III, onshore and offshore, increased 1,470 million barrels over the same period, and proved reserves in the total U.S. increased 942 million barrels.

By the end of 1967 proved reserves in the Gulf of Mexico were 7.6 percent of the national total, and the reserve-production ratio of slightly over 9 years was below the national average. A number of reasons have been given to explain the relatively slow development of this area. A predominant consideration was the existence of a substantial excess of crude oil productive capacity on nearby onshore areas. Drilling, completion and production technology had not advanced to the stage of assuring commercial production offshore. Presumably these problems, in the main, will not be a limiting factor in the future, as the need for additional domestic supplies increases and operating experience contributes to more economical exploitation of these potentially large supplies.

Other limitations to the early development of the OCS in the Gulf of Mexico go beyond economic factors. These include the myriad of uncertainties engendered by the legal relationships between operators and the federal and state governments when compared to onshore operations. For instance, inadequate allowables in relation to costs have been cited many times as a detriment to development. Certainly the leasing programs of the federal and state governments have also greatly influenced the level of exploratory activity. As later analysis will indicate, if these hinderances to development can be overcome the future potential of the OCS in the Gulf of Mexico will be enormous, if not critical to the future petroleum supply of the country.

B. Natural Gas Liquids

Several separate and distinct hydrocarbon classifications are included under the term "natural gas liquids." However, each classification has in common with the other the fact that although a liquid after removal from the gas, it existed as a gas prior to removal. The heavier material condenses first and is usually separated at or near the lease and marketed as "condensate." The lighter materials are scrubbed from the gas in gas processing plants and

called "gas plant liquids." These liquids include (from heaviest to lightest) natural gasoline, butane, propane, and ethane. Condensate is used almost exclusively by refineries, and it is not uncommon for condensate to be transported with crude oil in the same pipeline.

By definition, the natural gas liquids reserves estimates include only those liquids which are recoverable under existing economic conditions and in existing or planned facilities. Therefore, increases in NGL reserves are not wholly attributable to new discoveries, but are also attributable to new gas processing plants, or to deeper recovery of liquids in existing plants.

Natural gas liquids include three categories, (1) "field liquids" (condensate), (2) gas plant "LPG," and (3) gas plant "other." Gas plant LPG includes ethane, propane and butane. Part of the LPG goes into refineries, largely within the PAD District of production, and the remainder goes into the LPG markets, largely across PAD District lines. The gas plant "other" includes plant condensate, natural gasoline and other heavy material, all of which go to refineries usually in the District where produced. Likewise, field liquids are used in refineries, again mostly in the District where produced. Thus, interdistrict movement of natural gas liquids is generally confined to only a portion of the LPG which is not used in refineries.

Between the years 1956 and 1967 the production in the United States of natural gas liquids has almost doubled, much above the performance of both crude oil and even natural gas.

As shown on page 144, an increasing concentration of natural gas liquids production is found in District III which in 1967 accounted for 83 percent of national supply. However, as pointed out on page 145, reserves of natural gas liquids have not increased in proportion to gains in output and the Nation's reserve-to-production ratio stands at slightly more than 13 years, compared to 17.1 years in 1956. Although not as serious a long-term problem as has already been pointed out for natural gas or crude oil, still some consideration must be given to the adequacy of long-term supplies to meet expanded needs. The OCS volume of NGL production, shown on page 146, is still rather small, but is beginning to expand. In 1966 annual production of over 20 million barrels was a 100 percent increase over the rate only two years earlier. Reserves of NGL in the OCS area at the end of 1967 were reported to be about three-quarters of a billion barrels.

Additions to proved NGL reserves in the United States (see page 147), have trended upward over the postwar period as indicated by the following summary: [1]

Annual Additions To Natural Gas Liquids Reserves (MM Bbl.)

5-Years Ending	Annual Average
1952	581
1957	463
1962	743
1967	829

The reason for this upward trend is attributable to the AGA method of computing reserves, looking not only to in fact new discoveries, but increases in recovery capacity as well. Increases in the proved reserves of NGL due to improved recovery efficiency is illustrated by the Bbl./MMcf ratios of production and reserves, shown for both non-associated and associated-dissolved gas reserves on page 148.

During the 21-year period from 1947 through 1967, the barrels of natural gas liquid reserves per million cubic feet of natural gas reserves increased from 16.2 to 25.1 for non-associated gas, from 28.9 to 44.8 for associated-dissolved gas, and from 19.7 to 29.4 for the total.

The initial increase in barrels per million cubic feet was undoubtedly due primarily to the rash of gasoline plant construction after World War II, spurred by increasing state restrictions of the field flowing of gas. A plateau of about 24 barrels per million cubic feet was reached in the mid-Fifties. In the late Fifties, as a higher percentage of gas was processed and as the recovery of LPG reached higher levels, the reserves ratio started to climb again toward the current level of 29 barrels per million cubic feet.

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[1] See Appendix 6 for regional identification of these trends.

C. The Potential of Oil Shale, Oil Sands, and Coal Liquefaction

A literature search[1] of the current state of technology and economics in converting domestic oil shale, tar sand, or coal into petroleum indicates that these synthetic sources will not be developed in substantial magnitude in the immediate future, for two reasons.

First, the present state of research (bench scale for the most part) and the resulting absence of any proven cost estimates, the inherent lead time in moving from bench scale to commercial operation and the estimated capital and raw material requirements needed to support economically feasible plant sizes all militate against commercial development for a number of years. A recent Department of the Interior view in this matter was set out in *United States Petroleum Through 1980:*

> "Neither synthetic oil nor gas is expected to be an appreciable factor in the U.S. energy market before 1980. Even should their competitiveness be demonstrated by pilot plants now in being, the capital requirements of synthetic fuel plants are very great. Short of a crash program financed at least in part by the Government, many years would be required for construction of enough capacity to be of any significance as a supply source."

Second, the emphasis in recent years on developing synthetic petroleum has been primarily in response to the anticipated "petroleum gap"—that point in time when domestic conventional petroleum would no longer be able to fulfill domestic requirements at competitive prices. As discussed elsewhere in this report, events in 1968 indicate that this "gap" may have been postponed for an indefinite period. In fact, there has been verification of further postponement in the development of synthetics. First, the lack of interest shown by bidders for test leasing on shale oil lands in December 1968. Second, at approximately the same time, the Oil and Gas Conservation Board of Alberta, Canada deferred decision on an application by the so-called Syncrude group, after lengthy hearings, to produce synthetic crude from the Athabasca tar sands in part for consumption in the United States.

It should be noted, however, that industry and government continue to expend substantial sums in seeking to improve the technology of producing synthetic petroleum.[2] It is conceivable that, as technological improvements become available at lower costs, a relatively small scale volume of synthetic petroleum production could be in operation before 1985. The quantity of output, however, is likely to be of little significance when compared to the projected quantities from traditional sources. To quantify this expectation now might give an indication of later growth which current evaluation shows at best to be marginally attractive.

Beyond 1985, after a fuller evaluation of the potential resources of the OCS and the Arctic is available, it may be foreseen that substitutes for petroleum and natural gas from synthetic sources will still be at a competitive disadvantage.

IV. Projection of Supplies to Meet Petroleum Demand in 1975 and 1985: The National Model

The purpose of this section is to assemble all the elements of petroleum supply and demand, reviewed historically in Sections II and III, into a meaningful projection to the years 1975 and 1985 at the national level. The succeeding section of the report will show in some detail the expected trends of petroleum supply and demand at the District level, ending with a discussion of the expected role of the Outer Continental Shelf areas.

In constructing these projections it was vitally necessary to measure the impact of several alternate assumptions on key supply and demand factors, the most important of which was the expected rate of development of the North Slope. Another difficulty was experienced in forecasting the level of product imports and demand of residual fuel oil. To overcome

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[1] For example, see:

United States Petroleum Through 1980, U.S. Department of Interior, Office of Oil and Gas, July 1968.

Prospects for Oil Shale Development, U.S. Department of Interior, May 1968.

Reichl, Eric H., *Liquefaction and Gasification of Coal,* presented during a symposium – "An Assessment of Some Factors Affecting the Availability of Oil and Gas in the United States Through 1980," held by the U.S. Department of Interior on March 10, 1967, Washington, D.C.

Cameron, Russell J., *A Comparative Study of Oil Shale, Coal, Tar Sands as Sources of Oil,* presented at the Symposium on Petroleum Economics and Evaluation, AIME, Dallas, Texas, March 4-5, 1968.

Jones, Charles F., *Synthetic Fuels,* presented at the Western Mining Conference, Denver, Colorado, February 9, 1968.

[2] Undoubtedly, the very substantial, but variously estimated, reserves of synthetic petroleum which could be mined from these sources will continue to provide an incentive towards technological research. For example, the Department of Interior in May 1968 estimated the "known reserves" of shale oil reserves at 1.8 trillion barrels; and Cameron estimates of the petroleum potential which could be recovered from existing coal reserves are set at 225 billion barrels.

these problems the technique of forecast "ranges" was employed to illustrate, as best as possible, future supply and demand projections of several key factors. Only in this way can meaningful conclusions be drawn from the many uncertainties involved in looking ahead to the year 1985.

A. The National Supply and Demand Model

The basic procedure in constructing the national supply and demand model was to derive crude oil requirements by subtracting from domestic product demand the supply provided from other sources as shown below.

Crude Oil Requirements = Domestic Product Demand less Natural Gas Liquids less Net Product Imports less Refinery Gain

Crude oil production in the United States is, therefore, the difference between crude oil requirements and net crude oil imports.

On page 149 are shown the essential elements of the long-range petroleum supply and demand projection to the years 1975 and 1985 at the national level. Comparative statistics are shown for the year 1965 for historical reference.[1] This year was selected for two reasons: (1) to allow equal ten-year observation of trends to 1985; and (2) to eliminate supply distortions in 1966 and 1967 resulting from the Arab-Israeli confrontation which distorted long-term trends needed for this study.

A strong gain in domestic product demand is foreseen in the United States to the year 1985, subject to some uncertainty with regard to the consumption of residual fuel oil. In 1975 demand is estimated to reach a level of 16,200 MBD, or an annual increase of 3.5 percent. For the period 1975 to 1985 the growth in demand is expected to taper off somewhat, the degree of which is dependent on the expectations of consumption of residual fuel oil.

Two cases are shown on page 149 for projected total demand in 1985 reflecting a range of expectation for residual fuel oil usage after 1975. In Case A, it has been assumed that consumption of residual fuel oil will not be seriously affected by quality specifications (sulfur content, pour point, etc.). In Case B the consumption of residual fuel oil is assumed to be an essentially constant quantity reflecting adverse effects of pollution controls and interfuel competition. The range of these alternatives is estimated to be the equivalent of 600 MBD in 1985. As a result, total domestic demand in 1985 is projected in Case A at 21,300 MBD, in Case B at 20,700 MBD. The corresponding growth rate during the decade 1975 to 1985 in domestic demand is 2.8 percent per year with an optimistic outlook for residual fuel oil demand, but lowered to 2.5 percent per year under the lesser expectation.

Product imports, which are mainly residual fuel imports, are projected to reach a level of between 2,600 MBD (Case A) and 2,000 MBD (Case B) by 1985, after reaching a volume of slightly over 1,700 MBD in 1975. Under the conditions posed in Case B, additional crude oil imports are projected to retain the assumption that total imports will remain at 20 percent of total demand.

Natural gas liquids production is projected to increase to a level of approximately 1,900 MBD by 1975, an annual growth rate of 4.6 percent. Particular notice should be taken of this element of supply because it represents a direct substitute for crude oil in fulfilling product demand. By 1985 the output of these liquids is projected to increase to 2,500 MBD. As will be shown later, a significant part of this production in 1985 is expected to come from the Outer Continental Shelf areas.

The final factor in deriving crude oil requirements is the impact of refinery gain. Little attention has been given in other studies to this variable. The results of this study show, however, that in the future the requirements for crude oil will be considerably less because of the growing trend in domestic refineries to produce more liquid output, on a volume basis, than the quantities of liquid input (crude oil and NGL). In 1965 this gain amounted to 2.4 percent. By 1975 it is projected that nationally refineries will be producing 5.2 percent more products than required as feedstock, and by 1985 the proportion will approach 6.5 percent.[2] In volume terms, as shown on page 149, this would mean that by 1975 refinery gain would be 618 MBD, and by 1985 an amount of 950 MBD, compared to only 217 MBD in 1965.

Deducting the projected volumes of product imports, natural gas liquids and refinery gain from domestic product demand gives as a remainder the Nation's crude oil requirements. This statistic sets the limits for all sources of crude oil—from imports and production from onshore, from the North Slope, as well as from the OCS.

[1] To relate the projections with statistical data for the years 1966 and 1967, refer to page 131.

[2] For an illustration of a new refinery capable of achieving today's high levels of output per unit of input see — "Shuaiba (Kuwait): first all-hydrogen refinery," *The Oil and Gas Journal*, December 23, 1968, pp. 41-72.

Between 1965 and 1975 crude oil requirements in the United States are projected at a growth rate of 2.8 percent per year, or about 20 percent less than the projected increase in domestic product demand of 3.5 percent. A somewhat smaller rate of gain, 2.5 percent per year, is projected between 1975 and 1985. Still, the quantities considered are large—by 1985 the amount is 15,250 MBD or 69 percent more than crude oil requirements in 1965.

Crude oil imports by 1975 are projected to reach a volume of 1,459 MBD, a modest increase of 1.7 percent per year from 1965. After 1975 a diverging pattern for crude oil imports begins to appear. To retain the basic assumption of the study that total imports would remain throughout the forecast period at 20 percent of total demand, it was necessary to consider two levels of crude oil imports corresponding to the previously discussed alternative Cases A and B of product imports in 1985.

In Case A, which assumes expanding product imports after 1975, crude oil imports are projected to increase by only 200 MBD over the 10-year period. On the other hand, in Case B a much more accelerated pace of importation is projected, averaging 3.9 percent per year between 1975 and 1985, reaching a quantity of 2,140 MBD in 1985.

The impact on domestic production is readily apparent. The shifting of imports from products to crude oil within the 20 percent limitation is a direct reduction on the expected level of production from domestic sources. Even with this adverse situation, however, production from domestic sources will grow substantially—between 1965 and 1975 at a rate of 3.0 percent per year, and in the succeeding decade by an amount of 2.6 percent per year in Case A, and by 2.2 percent per year in Case B.

In summary, the national supply and demand model shows that domestic crude oil production, which was 7,804 MBD in 1965, can be expected to reach a level of about 10,500 MBD by 1975, and then continue to expand to a range of between 13,100 MBD to 13,600 MBD by 1985. It should be pointed out here, although discussed in detail in section V, that a significant part of this increase in production is projected to come from the North Slope of Alaska and the OCS.

The focal point in these projections now becomes the ability of domestic petroleum reserves to produce such substantial quantities over the period to 1985. The remainder of this section analyzes the domestic reserve potential in the following sequence—(B) the trend in the productive capacity of crude oil reserves, (C) the trend in finding rates and recovery rates of crude oil reserves, (D) the potential impact of North Slope crude oil production on domestic requirements, and (E) the role of crude oil reserves in the Outer Continental Shelf.

B. The Trend in the Productive Capacity of Crude Oil Reserves

Productive capacity of oil wells in the United States has increased at a substantially greater rate than proved reserves, and as a result, by December 1967 productive capacity in the United States was estimated by the American Petroleum Institute at 12,289 thousand barrels per day, almost 50 percent greater than average daily production in 1967.[1] Most of the increase in this productive capacity in recent years has occurred in Southern Louisiana, both onshore and offshore; but even so, Texas is still reported to account for 43 percent of the total productive capacity as of December 1967 and 60 percent of the "idle" capacity.

Although productive capacity at the national level is more than adequate to meet short-term requirements, it must also be recognized that many areas are producing at or very near productive capacity. These include most of Districts I, II, and IV, as well as a substantial portion of older producing areas in District V, the West Coast. This fact is pointed out on page 150, which shows a comparison of actual production during the first six months of 1968 with the productive capacity as of January 1, 1968.[2]

For the purposes of this study, it does not appear necessary to consider productive capacity a serious detriment to long-term supply as long as adequate new discoveries of reserves are forthcoming. In fact, recent trends indicate that historic rules-of-thumb relating productive capacity to the reserve-to-production ratio are becoming less pertinent to availability of adequate long-term supply. With an increasing productive capacity projected into the future, the Department of Interior has concluded that, "It no longer appears necessary to maintain a ratio of proved reserves-to-production in the vicinity of 12 to 1 to insure the producibility

[1] However, this productive capacity is measured for a short 90 day period only, based on a number of working assumptions. See *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1967*, at pp. 24-28.

[2] The IPAA definition of productive capacity used here is the average rate of production from existing wells that could be maintained for a period of from *six to twelve months.*

of reserves at required rates."[1] In this context it appears that productive capacity in the future will be of major concern only to those assessing the immediate, short-range supply situation under such conditions as threats to the national security or other unusual supply situations.

In light of these considerations, the important question then becomes the adequacy of new discoveries of crude oil reserves in the United States.

C. Trend in Finding Rates and Recovery Rates of Crude Oil Reserves

The Department of Interior, in their 1968 publication *United States Petroleum Through 1980,* surveyed crude oil resources in the United States and also constructed an estimate of future new supplies of petroleum to the year 1980. A brief review of Interior's findings is therefore in order:

Looking first to the resource base, authorities seem to be in general agreement that approximately 400 billion barrels of crude oil have been found in the United States to date, according to Interior. This conclusion is based primarily on an American Petroleum Institute estimate of 381 billion barrels of original oil in place proven as of December 1967, compared to 404 billion barrels estimated to have been found as of December 1965 by the Interstate Oil Compact Commission. Extrapolating this evidence, Hendricks has estimated that about 1,600 billion barrels of crude oil was originally in place for the United States, including the Outer Continental Shelf in the Gulf of Mexico and California out to 120 feet of water depth.[2] This estimate was subsequently revised upward to 2,000 billion barrels in place, when the Outer Continental Shelf is extended to 600 feet of water depth, including the Gulf of Alaska.[3]

With these estimates as a background, the Department of Interior proceeded to construct an original and definitive analysis of the near-term finding rate (to 1980) of proved crude oil reserves in the United States. The steps taken and conclusions reached may be summarized as follows:

(1) The crude oil recovery rate is projected to increase from 30 percent in 1965 to 37.5 percent in 1980, yielding an additional 29 billion barrels of economic recoverable reserves from oil in place as of 1965.

(2) Based on a trend analysis of crude oil discoveries since 1920, it is estimated that an additional 72 billion barrels of crude oil in place will be discovered between 1965 and 1980 which, at a 37.5 percent recovery, will yield 27 billion barrels of recoverable reserves. Summating 29 and 27 billion barrels, Interior therefore estimates about 56 billion barrels of recoverable reserves being made available between 1965 and 1980. This is some 4 billion barrels in excess of cumulative production of 52 billion barrels estimated over the 15-year period.

(3) *However,* actual discoveries were some 7 billion barrels below the "trend line" as of 1966, coinciding with declines since 1957 in exploratory drilling, geophysical crew months and new oil fields found. Therefore, if new reserves are to offset withdrawals between 1965 and 1980, improvements in recovery rates must be accelerated, or a larger reserve of crude oil discoveries must be forthcoming.

The trending technique used by Interior was to fit a Gompertz curve to the cumulative discoveries of original oil in place and to project this curve to the year 1980.[4]

These techniques and findings represent a useful point of departure. In the end result, the Department of Interior seemed concerned that 56 billion barrels of new crude oil reserves will, in fact, be added between 1965 and 1980, based on prevailing historical trends. Accordingly, it seems appropriate to discount somewhat the recovery and finding rates reached by Interior.

As a first approach it was decided to average the annual additions of recoverable reserves implied by the Interior analysis (approximately 3,733 million barrels per year) and the projected rate of domestic crude oil production utilized in this study. By this approach it is assumed that industry exploration effort will be in some proportion to replacing current

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[1] *United States Petroleum Through 1980,* op cit., at page 31.

[2] Hendricks, T. A. , *Resources of Oil, Gas, and Natural Gas Liquids in the United States and the World,* U.S. Geological Survey Circular 522, Washington, D.C., 1965.

[3] Hendricks, T. A., and Schweinfurth, S. P., unpublished memorandum dated September 14, 1966 as cited in *United States Petroleum Through 1980,* op. cit., at page vii.

[4] For an explanation of the Gompertz curve and its uses in analyzing discovery trends, see Moore, C. L., *Projections of U.S. Petroleum Supply to 1980,* Office of Oil and Gas, U.S. Department of Interior, Washington, D.C., 1966. Also see footnote 5 at page 17 of *United States Petroleum Through 1980,* op. cit., for more details regarding the methods used by the Department of Interior in fitting the Gompertz curve to the reported data.

production withdrawals, allowing for a longer lead time for improving recovery rates and for more fully exploring new oil provinces such as the California OCS and the deeper waters in the Gulf of Mexico. By this simplified approach, additions to crude oil reserves are projected to amount to 28 billion barrels over the 8-year period from 1968 to 1975, representing an annual average reserve addition of 3,500 billion barrels.

By a similar approach of averaging the implied Interior additions to reserves with the projected rate of domestic crude oil production from 1975 to the year 1985, it was determined that an additional 40.0 billion barrels of recoverable crude oil reserves would be found, or an average of 4.0 billion barrels per year.

Using this approach these new reserves would not be sufficient to replace crude production requirements, and as a result proved and indicated reserves in the United States would decline slightly from 39.0 billion barrels as of December 1967 to about 38 billion barrels in December 1985 (page 152), and the indicated reserve-production ratio for the United States would decline from 12.8 years in 1967 to 8.2 years in 1985.

These deficiency findings, of course, are not novel. For several years industry and government authorities have projected a need for supplemental sources of crude oil to meet an impending "energy gap." Based on these types of analyses, the year 1975 has frequently been used as that year when "supplementation" should commence.[1] Various supplemental sources have been advanced—an increase in import levels; production of petroleum from coal, from oil shale and from tar sands; and improved incentives to increase domestic discoveries.

Yet, with the benefit of hindsight, these projections must be placed in abeyance until the North Slope potential is reasonably defined. Any statistical analysis, such as the Gompertz curve technique, is necessarily based on reported data pertaining to discoveries and recovery rates from known producing provinces. These methods cannot anticipate or forecast a North Slope type of discovery. Yet the ink had hardly dryed on the Department of Interior study when the DeGolyer and McNaughton appraisal of the Prudhoe Bay discovery was announced. As discussed below, the North Slope momentum, as of December 1968, has built up to a point where it would seem to have a high probability of moderating the Department of Interior's concern that crude oil discovery rates will not be sufficient to offset withdrawals from reserves up to the year 1980, on the basis of anticipated recovery rates. Indeed, there is an increasingly expressed view that the North Slope may well postpone concern for domestic petroleum supplies well beyond the year 1980.[2] For this reason, it is necessary to estimate future crude oil production from the North Slope and to measure the prospective impact of this production on domestic crude oil requirements.

D. The Potential Impact of North Slope Crude Oil Production on Domestic Requirements

The announcement in mid-1968 of the discovery of large, new oil reserves at Prudhoe Bay on Alaska's North Slope, and the subsequent great amount of speculation as to its future impact on the U.S. oil industry, is a complicating factor at this time in assessing long-term supply trends. With such limited time and facts to make an appraisal for this report, only the most preliminary and broad projections can be made. Nevertheless, enough evidence is at hand, verified by corporate announcements with regard to the development and expansion of commitments in the area over the next few years, to require that an assessment be made to include production from this new oil province in the supply projections as early as 1975, and certainly thereafter.

In inserting North Slope oil into the supply picture, a series of judgments must be made as to volume, timing, transportation, and refinery center or market where this oil will be used. With the possible exceptions of the shifts in oil supply caused by the Arab-Israeli confrontations in 1956-57 and 1967, there has not been any new oil supply situation in the postwar period to match the potential impact of the North Slope oil for the United States petroleum industry. The ramifications of this discovery, further, must be considered even to the international level. One petroleum authority has suggested that, ". . . the center of gravity of North American and Russian oil will now shift to the Arctic, and will become firmly settled there."[3]

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1 For example, see "Report of an Application of Atlantic Richfield Company, Cities Service Athabasca Inc., Imperial Oil Limited and Royalite Oil Company, Limited, under Part VI A of the Oil and Gas Conservation Act," Oil and Gas Conservation Board, Calgary, Alberta, December 1968. The target date for the "energy gap" is variously estimated, depending primarily on whether indicated reserves are added to proved reserves. The Syncrude evidence pointed to the year 1975 and used a domestic reserve-production ratio of 9 years as a "safe" minimum inventory, in relation to volumes of crude oil which would be imported from *overseas* production sources.

2 "Slope Seen Answer to Output Decline," *The Oil and Gas Journal*, October 21, 1968, page 50.

3 *Petroleum Intelligence Weekly*, November 4, 1968, pp. 1, 2.

For purposes of this report it was decided that a simplified set of three North Slope production levels to the terminal year of 1985 would be assumed and the impact of these production levels on the remaining domestic production expectations would be analyzed. In doing this it was further assumed that, at least through 1985, production from the North Slope would be marketed only within the United States and, therefore, no exports of crude oil to foreign markets are projected. Further, although there are obvious questions as to the expected price to be obtained for this crude oil, and the effect of the price on other domestic crude oils, it appears to be too early to reach any conclusions on this aspect and, therefore, it has been disregarded in the analysis.

Finally, and this may be crucially important, some determination would appear to be necessary to predict in what manner North Slope oil will flow to U.S. markets. Several alternatives have been suggested—(1) a pipeline to an all-weather port on the southern Alaskan shoreline and hence by tanker to the West Coast; (2) a pipeline directly to the Middle West or East Coast via Canada; (3) a polar tanker route, by submarine or surface vessel, across the Arctic Ocean and into the Northern Atlantic to Eastern or Western Hemispheric markets;[1] and (4) similar ocean transportation as in (3), but traveling westward through the Bering Strait to Northern Pacific markets. These transportation routes have, of course, varying economic, political, legal and technological advantages and disadvantages, the evaluation of which is beyond the scope of this report.

Nevertheless, certain decisions had to be made with regard to the movement of North Slope oil. In general, it was assumed that the first increments of production would go to the West Coast of the United States (District V). As production increased, a first limit would be reached when all imports into District V, representing deficiency in local supply, would be potentially supplanted. Then, any additional volumes from the Slope would move to markets in either the Middle West and/or the East Coast (Districts I and II). Within the time reference of the forecast to 1985, it was not assumed that any additional markets could be served with realistic production alternatives. No analysis was made beyond 1985.

Having made the decision that North Slope oil potential is a significant supply factor for the future and the general manner by which the oil would flow into the United States market, it is next necessary to project reasonable levels of producing rates.

Sustained producing rates depend, of course, on the amount of reserves indicated for the North Slope area for the forecast period. The initial announcement on the Prudhoe Bay by Atlantic Richfield reported a consultant's appraisal of from 5 to 10 billion barrels of oil for this field alone.[2] On the basis of this discovery, exploration activity in the North Slope area, the adjacent geologic basin centered on the MacKenzie River Delta in Canada, and into Beaufort Sea and the Arctic Islands, has increased spectacularly. Recent reports speculate that "chances are excellent that anywhere from 10 to 20 billion barrels of recoverable oil will be proved up in Northern Canada and the Arctic regions during the next five years."[3] "Ultimate recoverable oil reserves along an 800-mile stretch of coastal plain on the Arctic fringe of North America may be in the order of 50 to 100 billion barrels."[4]

On the basis of these very early indications of North Slope reserve potentials, it would appear that a range of from 10 to 25 billion barrels would be an order of magnitude of reserves which might be expected, barring some dramatic unforeseen event during the forecast period through 1985.

Using this range of reserve estimates, three projected production levels from the North Slope have been constructed to identify and quantify the impact of the North Slope production upon the U.S. supply and demand forecast. These are first a "low" projection which amounts to a production of 500,000 barrels per day in 1975, reaching an amount of 1,500,000 barrels per day in 1985. A second "medium" projection of 750,000 barrels per day in 1975 which by 1985 will have grown to 2,250,000 barrels per day or triple the decade earlier rate; and finally, a "high" projection beginning with 1,000,000 barrels per day in 1975 advancing to 3,000,000 by 1985. These three projections correspond roughly to a range of reserves of from 10 to 25 billion barrels.

To test the reasonableness of these production

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[1] A major test to determine the feasibility of this alternative was announced in December 1968, to begin June 1969. The U.S. Flagship S.S. Manhattan, a 115,000 ton tanker is to be modified to strengthen its hull, to install an ice-breaker bow, a propeller and a rudder protector. The contemplated voyage will include passage from Prudhoe Bay, through a northwest passage to the U.S. East Coast. *Oilweek*, December 23, 1968, page 19.

[2] Press Release, Philadelphia, Pa., July 18, 1968.

[3] "Arctic oil may bridge supply gap," *Oilweek*, September 30, 1968.

[4] "100 billion bbls. on Arctic Coast," *Oilweek*, September 30, 1968.

projections, a comparison was made to the recent history in Libya where reserves of equal importance were discovered in 1958, a decade before the North Slope announcement. Production in Libya commenced four years after discovery (1962), and increased to a level above one million barrels per day within three years (1965), and is estimated to be 2.5 million barrels per day in 1968.

As illustrated in Chart C-21, the "high" projection of North Slope production coincides roughly with the growth of Libyan production during similar periods from initial discovery, while the "low" projection corresponds to a pattern of about half the Libyan rate. It will be noted, however, that Libyan production in 1968, ten years after discovery, is considerably above the comparable projection for the North Slope "high" production projection by 1978.

For forecast purposes, the initial timing of the delivery of the North Slope oil to market was not found crucial to this analysis. Dates as early as 1971 have been reported for completion of pipelines servicing the North Slope,[1] which may seem optimistic. However, it does seem realistic to presume that movements will begin by the forecast year, 1975.

The technical and cost barriers in extracting North Slope oil will require that only large discoveries be developed. This means a commercial scale production of magnitude much higher than normally encountered in the United States. On the other hand, practical market considerations must place some limits on the pace with which this new oil can enter the domestic market. It is assumed, therefore, that although the production levels will be high initially, the increase from the initial levels will be arithmetic rather than geometric, a pattern similar to that in some foreign producing areas. That is, the gains in production envisioned will be in equal increments over five-year periods. This is illustrated below, summarizing the before mentioned three cases of projected North Slope production levels:

North Slope
Production Projections
(Thousand Barrels Per Day)

	"Low"	"Medium"	"High"
1975	500	750	1,000
1980	1,000	1,500	2,000
1985	1,500	2,250	3,000

[1] *The Oil and Gas Journal*, September 23, 1968, page 76.

Based on these projections it is clear that the North Slope has the potential of making a substantial contribution towards meeting domestic crude oil requirements over the forecast period. If the North Slope production is assumed to be at the lower end of the forecast range, approximately 5 percent of domestic crude oil requirements will be fulfilled by 1975 and 12 percent by 1985. If the North Slope production is assumed to be at the higher end of the forecast range, approximately 10 percent of domestic crude oil requirements will be fulfilled by 1975 and about 24 percent by 1985. The remainder of these requirements will presumably be met from known producing areas, primarily if not wholly from those areas which are the subject of special study by the Department of Interior.

A detailed statistical compilation on page 152 shows the impact of various projections of North Slope producing rates on the previously estimated reserves and reserve-production ratio. Besides the three projected levels of North Slope production, a fourth illustration is given, for comparative purposes, to show what results would have been obtained if the North Slope discovery had not occurred.

1. Potential Impact of a Minimum North Slope Production on Domestic Reserves

Under the case of the assumed *minimum* North Slope production, the crude oil production required from remaining known domestic producing areas would increase from 3,038 million barrels in 1967 to 3,457 million barrels by 1975, and to 4,122 million barrels by 1985. The ability of the domestic reserves, excluding North Slope, to produce these amounts are tied, in degree, to the annual reserve additions of recoverable crude oil. Annual additions in this case are projected as outlined in the previous section; e.g., averaging the annual additions trended by the Gompertz curve statistical techniques used by the Department of Interior, and projected domestic crude oil production excluding the North Slope. New reserves under these conditions are projected to amount to about 28 billion barrels over the 8 years from 1968 to 1975, and to about 38 billion barrels over the 10-year period 1975 to 1985. These new reserves represent annual averages of about 3,500 million barrels over the 8-year period, and 3,800 million barrels over the latter 10-year period, less than what would have been projected if domestic production were not anticipated from the North Slope. This reduction in projected new reserves could reflect in degree a shift in exploratory and development efforts away from onshore areas towards the North Slope

activities. However, this reduction in new reserve levels should be substantially less than the reduction in the production requirements, and as a result total reserves (including indicated as well as proved) are projected to remain practically constant over the forecast period, amounting to about 40 billion barrels in 1985 compared with 39 billion barrels in 1967.

With production increasing and reserves remaining relatively constant, the reserve-production ratio for the United States, excluding the North Slope, should decline somewhat to about 9.8 years in 1985, compared with 12.8 years as of 1967. If the North Slope reserves and production, as assumed in the minimum case, are added to the remainder of the United States, total domestic reserves should increase to about 48.2 billion barrels by 1985, and the reserve-production ratio would be about 10.3 years.

2. Potential Impact of a Maximum North Slope Production on Domestic Reserves

If North Slope reserves and production approximate *maximum* projected levels, the remaining crude oil production required from the known domestic producing areas would increase from 3,038 million barrels in 1967 to 3,275 million barrels in 1975, and to 3,575 million barrels in 1985. Using the same statistical projection techniques as described for the minimum North Slope case, new reserves in the known areas would amount to about 28 billion barrels over the 8-year period from 1968 to 1975, and to about 36 billion barrels over the 10-year period from 1975 to 1985. On the basis of these assumptions total domestic reserves, excluding the North Slope, should increase slightly over the forecast period to about 42.5 billion barrels by 1985. Even with this increase, however, the reserve-production ratio would decline somewhat to 11.9 years by 1985. If the North Slope reserves, as assumed under the maximum case, are added to the remainder of the United States, the total domestic reserves would increase substantially to about 58.9 billion barrels in 1985, and the reserve-production ratio would be about 12.6 years in 1985.

Taking into consideration the Department of Interior's anticipation that productive capacity will continue to increase at a rate greater than additions to reserves, it may be concluded that projected production from the North Slope will have a most beneficial impact on remaining domestic reserves through 1985, and possibly for some time thereafter.

E. The Role of Crude Oil Reserves in The Outer Continental Shelf

Commercial interest in the OCS, as evidenced by recent leasing activity, certainly seems justified on the basis of crude oil reserves estimated to be within economic and technological reach in this area. McKelvey recently estimated potential recoverable crude oil resources in the OCS (out to 200 meters of water depth) under current economics and technology to be–

Gulf of Mexico	–	60 billion barrels;
Pacific OCS	–	8 billion barrels;
Alaska OCS	–	54 billion barrels;
Atlantic OCS	–	42 billion barrels;
Total (rounded)		160 billion barrels.[1]

Within wide parameters of these types of estimates, the OCS crude oil resources could account for about 23.5 percent of the total estimated potential crude oil reserves in the United States, within economic and technological reach.[2] Looking to the four OCS areas, the 23.5 percent breaks down into 8.5 percent for the Gulf of Mexico, 1 percent for the Pacific OCS, 8 percent for the Alaska OCS, and 6 percent for the Atlantic OCS.

Of these OCS areas the Gulf of Mexico has been the only source of proved crude oil reserves and production as of December 1967. (Even so, proved reserves and cumulative production in the Gulf amounted to only 3.8 billion barrels, as of December 1967.) While recent discoveries indicate the Pacific OCS commenced in 1968 to make a modest contribution to domestic crude oil supplies, it is clear that major supplies of crude oil from the OCS lie in the future.

Exploration and drilling activity throughout the United States will undoubtedly be affected by the anticipated exploration and drilling for crude oil reserves in the North Slope, the OCS not excepted.

[1] *Potential Mineral Resources of the United States Outer Continental Shelves*, V. E. McKelvey and Others, U.S. Geological Survey, 1968, in press. The method used by McKelvey for calculating these estimates follows that described in U.S. Geological Survey Circular 522, *Resources of Oil, Gas, and Natural Gas Liquids in the United States and the World*, by T. A. Hendricks. The estimates are based on a 40 percent recovery factor for oil, "in order to reflect anticipated near term gains in recovery technology (NPC, 1967). . ."

A second set of estimates is also presented in this publication based on Hendricks' "favorability ratings," amounting in the total to 190 billion barrels, of which 80 billion are attributed to the Gulf of Mexico, 72 billion to Alaska, 30 billion to the Atlantic OCS, and 12 billion to the Pacific OCS.

[2] Estimated at 640 billion barrels by applying a 40 percent recovery rate to the previously referenced Hendricks estimate of 1,600 billion barrels of crude oil in place in the United States, including the OCS.

Yet, the momentum of drilling and producing activity in the Gulf of Mexico, assuming continued satisfactory profit levels, ranks the potential of that area more favorable than most if not all areas in the United States, except the North Slope at this time. Adding a continuing activity in the Pacific OCS, despite recent disappointments, it seems reasonable to expect new reserves of crude oil in the OCS to increase at a more rapid rate than new reserves onshore, excluding the North Slope. This view is confirmed by a statistical projection of the new reserves of crude oil in the United States, computed both to include and exclude the OCS. The Gompertz curve was fitted to the cumulative proved reserves of crude oil reported by the API, and the trend lines were projected with new reserves representing, in effect, a first derivative of the projections.[1]

Within this context, new reserves of crude oil in the Gulf of Mexico and in the California OCS are projected to amount to about 6 billion barrels over the 8 years from 1968 to 1975, and approximately 16 billion barrels over the 18 years from 1968 to 1985. Thus, these two OCS areas are projected to account for about 22 percent of the total domestic new reserves, excluding the North Slope, from 1968 to 1975, and about 25 percent from 1968 to 1985. It is immediately noticeable that the ratio of new OCS reserves to total new reserves (excluding the North Slope) is substantially higher than the ratio of potential economic recoverable reserves in the Gulf of Mexico and the Pacific OCS as compared with the total United States (9.5 percent). Two comments can be made in this regard. First, the North Slope should be added to the denominator of the new reserve "fraction," which would reduce this percentage. Thus, if a maximum new reserve as high as 30 billion barrels is realized on the North Slope by 1985, the OCS areas would account for about 17.5 percent of the total new supply in the United States over the 18-year period to 1985. Even this percentage is high relative to the total estimated recoverable reserves. Second, this difference can be accounted for by the relatively higher profitability of crude oil production in the Gulf of Mexico compared with onshore, as set out in Section II of this report, "Cost of Finding and Producing Hydrocarbon Supplies." The Gulf of Mexico is expected to account for some 12 billion barrels of new reserves over the 18-year period to 1985, compared with 3.5 billion barrels of estimated new reserves for the California OCS. Over the shorter term from 1968 to 1975, 4.5 billion barrels are estimated to be proved up in the Gulf of Mexico, compared with 1.5 billion barrels in the California OCS.

[1] As in the case of the Gompertz curve projection by the Department of Interior, this analysis does not encompass new major producing areas such as the North Slope, and prospectively the Alaska OCS and Atlantic OCS.

The fact that the rate of increase in new reserves in the OCS exceeds that for new supplies onshore, excluding the North Slope, leads to crude oil production in the OCS increasing at a more rapid rate than onshore, assuming the reserve-production ratio in the OCS remains at its 1967 level. On this basis, the Gulf of Mexico is projected to increase its crude oil production from 256 million barrels in 1967 to about 450 million barrels in 1975, and to 750 million barrels by 1985. This projection represents an annual average growth rate from 1967 to 1985 of 6.2 percent, compared with a 2.4 percent annual average growth rate for total domestic crude oil production (including the North Slope). Because of this rapid growth rate, crude oil production in the Gulf of Mexico would account for 16.1 percent of total domestic crude production in 1985 compared with 8.4 percent in 1967. Because of this strong growth potential it is concluded that the level of Gulf of Mexico production will be the same irrespective of the alternative projections for the North Slope. The impact will be felt elsewhere.

Production in the California OCS, it is concluded, will be affected by larger volumes from the North Slope. Under the "low" projection California OCS production is estimated to be 110 million barrels in 1975, increasing to 182 million barrels in 1985. Under the maximum or "high" North Slope expectation, no increase in production is foreseen between 1975 and 1985 from the level of 110 million barrels.

The following tabulation summarizes the above projections with quantities expressed in thousands of barrels per day.

	Gulf OCS		California OCS	Total OCS
1975	1,220 MBD		300 MBD	1,520 MBD
1985	2,050 MBD	"low" NS	500 MBD	2,550 MBD
		"med." NS	400 MBD	2,450 MBD
		"high" NS	300 MBD	2,350 MBD

Thus, in 1975 the combined production from both OCS areas would equal approximately 1.5 million barrels per day, or 14.5 percent of total

domestic crude oil production. In 1985 the range of estimates of 2.35 to 2.55 million barrels per day would be equivalent to 17.3 to 18.8 percent of total production, and would be approximately equal to the projected volume of both foreign crude oil and product imports.[1]

The Gulf of Alaska and the Atlantic OCS—Two Special Cases

Based on the assumptions adopted in this report, it is seen that domestic crude oil and natural gas liquids supplies will probably be sufficient to meet the projected demand to at least 1985, without expanding petroleum imports beyond their current contribution of about 20 percent, and without introducing any substantial production of domestic synthetic petroleum into the United States supply-demand structure, and without projecting petroleum production from either the Alaska OCS or the Atlantic OCS.

Yet these two OCS areas command considerable promise. McKelvey estimates the potential recoverable crude oil resources under current economics and technology to be about 54 billion barrels in the Alaska OCS, and 42 billion barrels in the Atlantic OCS, to a water depth of 200 meters. A cautious confirmation of this optimism has been expressed by industry with respect to both the Alaska OCS and the Atlantic OCS.[2] However, there has been little exploration and no drilling to ascertain whether or not reserves of these or other magnitudes in fact exist. Thus, it is possible to speculate only with regard to the impact if reserves of a commercial magnitude are found in due course in either the Alaska OCS or the Atlantic OCS.

Unquestionably the Atlantic OCS is a strategic location, offshore from District I with its very substantial petroleum markets dependent in degree upon overseas imports. If commercial reserves are found, it seems reasonable to expect these supplies will orderly and economically find their way to the market place. This would be true whether production commences before or after 1985. In this regard if sufficient reserves are found, it may be reasonable to project a production buildup similar to the Gulf of Mexico experience where production has increased slowly from some 300,000 barrels in 1948 to 256 million barrels in 1967. With a like production build-up it is quite probable that the growing demand could absorb the Atlantic OCS without seriously disrupting other supply sources. This would be the case even if commercial production is established as early as 1975.[3] Beyond 1985 the Atlantic OCS could become an important, even vital, supply of crude oil towards meeting the ever-growing petroleum requirements in the United States.

The Alaska OCS is not now located near petroleum markets and is attended by very difficult climatic conditions, both factors having an impact on the prospective cost of finding and producing crude oil.[4] For these reasons it seems likely that commercial production can occur only at substantially higher economic incentives than required of other OCS areas. For example, the Gulf of Alaska would seem to require the potential which now prospectively attends the North Slope. If these levels are achieved in the Gulf of Alaska, in combination with the Northern part of Alaska and Canada, it will create a new world oil center comparable to the Middle East. It is beyond the scope of this undertaking to fully assay the implications of such a potential supply center.

F. Prospective Production of Natural Gas Liquids

Projected future U.S. production of natural gas liquids is shown in Table C-23 for 1975 and 1985 together with 1965 volumes for comparisons. It is expected that during this 20-year period the national volume of NGL production will double and amount to 1,184 million barrels by 1985. An increasing proportion of NGL production is ascribed to PAD District III which will account for almost 87 percent of the volume in that year compared to 83 percent in 1965. The Gulf of Mexico will be a very important supply point for natural gas liquids mainly as a result of the sharp projected increase in natural gas production, as outlined in Chapter B.

Between 1975 and 1985, growth in natural gas liquids production, as shown on page 153, in District III will be much higher offshore, 7.8 percent

[1] The above percentage comparisons refer only to the previously described Case A in 1985. Under Case B the OCS share of national production would be increased to 0.6 percent.

[2] See, for example; "Oil and Gas Extraction Technology," a paper presented by T. D. Barrow before the Mineral Resources of the World Ocean Symposium, Newport, Rhode Island, July 12, 1968; "Exploring Offshore Megalopolis," a pamphlet prepared by P. T. Fowler, Dallas, Texas, 1968; *The Oil and Gas Journal*, "Newsletter," January 27, 1969.

[3] It is difficult to envision a critical need for testing the Atlantic OCS for crude oil supplies, such as the critical need for testing the Atlantic OCS for natural gas supplies. However, the Atlantic OCS is an untested area and could be gas prone or oil prone.

[4] "Operators show why costs high in Alaskan waters," *The Oil and Gas Journal*, July 15, 1968, page 116.

per year, compared to the onshore average of 1.2 percent per year. By 1985 some quantities of liquids are to be expected from the Atlantic OCS, assuming the anticipated initial volume of natural gas as discussed in Chapter B is realized.

Some Implications Regarding Future NGL Reserves in Alaska

At the end of 1967, reported gas reserves in Alaska were 93 percent non-associated and only 7 percent associated-dissolved. Thus, these reserves could be produced independently of any crude oil production and marketed if sufficient demand for the gas existed. To date, local conventional demand for Alaskan gas has been small, and attention has turned to export as liquefied natural gas (LNG) and to chemical conversion to fertilizer components.

In the future, this ratio of non-associated to associated-dissolved is likely to change as an outgrowth of the North Slope oil play. Nationwide, the ratio of associated-dissolved gas to crude oil is currently 2,160 cubic feet per barrel.[1] If this same ratio were to apply to the reported 5 to 10 billion barrels of possible reserves of the Prudhoe Bay field, the imputed associated-dissolved gas reserve would be 11 to 22 trillion cubic feet. Thus, it would seem that the gas reserves of Alaska would tend more toward associated-dissolved and less toward non-associated.

Markets for gas liquids in Alaska are also limited, hence any significant production must be exported for consumption. Export of such limited volumes of hydrocarbons as represented by natural gas liquids alone would be prohibitive in terms of cost. However, export in mixture with a much larger volume of crude oil could become feasible. Hence, production of gas liquids from associated-dissolved gas and transportation in mixture with the accompanying crude oil may be feasible.

Even mixing with crude oil does not entirely absorb all the potential gas liquids. The natural gasoline and butane products could be absorbed. However, propane mixing with crude oil would be quite limited because of the high vapor pressure of propane.

Significant recovery of propane no doubt will be delayed until export demands justify the required separate propane storage and transportation facilities. Japan is a significant importer of propane, and may be a potential market for Alaskan propane. In the U.S., there are recurring, though limited, requests for permission to import propane under the Oil Import Administration regulations. Presently, such imports as occur come from the Caribbean. Alaska-based propane destined for domestic markets would be preferred from the viewpoint of being exempt from the mandatory import program. However, the long distance to the mainland markets is a negative factor. Indeed, the need for such imports of propane into the U.S. mainland could be justified only by a significant shortage of propane. If such a shortage does develop, it is not indicated much before 1975.

Along the Texas Gulf Coast, a number of cycling projects have been under way for some years, wherein gas is withdrawn from the reservoir, processed for liquid extraction and returned at least partially, if not wholly, to the reservoir. This is done for several reasons. If there is no gas sale, cycling can result in current liquid revenue while waiting for gas revenue to develop. Cycling also removes liquids from the reservoir gas which could be lost in the reservoir by retrograde condensation upon pressure reduction. Also, a gas cap above an oil horizon may be cycled for liquid revenue still maintaining the gas cap pressure necessary for production of the oil.

It is not likely that operations will be instituted in Alaska merely to obtain current liquid revenue until after the more important oil production and shipment program is under way. After that, gas liquid revenues may become relatively more important. Also it is unlikely that gas liquids will be produced from cycling or other projects which do not result in crude production and which may exceed the capacity of other crude production for blending and commingled transportation.

For natural gas liquids, in summary, a large expansion in output is foreseen from the Gulf of Mexico OCS by 1985, while in Alaska limited availability and disadvantageous geography indicate limited future potential. The latter situation could change, however, if economics indicate the attractiveness of foreign markets such as Japan.

V. Projections of Supplies to Meet Petroleum Demand in 1975 and 1985: The Regional Model

Although the national model projection of future petroleum supply and demand describes the overall environment to be expected in the years ahead, it is necessary to examine in more detail these forecasts to find the role of the OCS. The next step, therefore, is to break down the national projection into regional or PAD District models and finally, within these District models, to assess the production expectations of both offshore and onshore areas.

[1] For Alaska, the ratio of 251,559 million cubic feet of associated-dissolved gas to 381 million barrels of oil is 660 cubic feet per barrel.

It must be stressed at the outset of this section that the degree of possible error in projections to 1985 is much larger for the District models than the national model. One principal reason for this is that in the United States there are various centers of crude oil supply as well as product supply from refineries. In the postwar period a vast transportation system has been constructed between supply centers and consuming regions; and these transportation systems are in a constant state of flux and expansion in response to changing economics of supply.

The recent building of Capline, a large-diameter crude oil pipeline, from the producing area in South Louisiana to refinery centers in the Great Lakes region is an example of the response to a changing crude oil supply situation. The location of future construction of new or expanded product pipelines within the country is difficult to predict, but construction will occur before 1985. Likewise, the manner and timing with which crude oil will come from the North Slope of Alaska to the "lower Forty-eight" is presently undecided. Nevertheless, projections to 1985 require that logical and consistent decisions be made on these key supply variables.

Within these limitations it is possible to draw certain conclusions on petroleum supply and demand adequate enough to assess the needs of this study. Therefore, while some may quarrel with individual crude oil and product flow quantities within the several projections, it is assumed that the net effect of the disagreements would not be important, leaving the general conclusions on crude oil production from offshore areas within a reasonable degree of expectation.

The discovery of oil on the North Slope of Alaska in significant volume, as described in the previous section, required that some adjustments in procedure be made in projecting supply and demand below the national level. It was decided, therefore, that, for forecast purposes, PAD District I (the East Coast) and District II (the Midwest) would be combined to represent one region which had the similar characteristic of local crude oil deficiency in relation to requirements. The other Districts (III, the Southwest; IV, the Rocky Mountains; and V, the West Coast, including Alaska) were treated separately as areas of crude oil surplus or potential surplus.

The general procedure in making the forecasts was to first project supply and demand balances in the crude surplus Districts IV and V (with North Slope alternative production levels) and then to move excess crude oil from these Districts to Districts I and II (the deficit area), and thence to supply any additional crude requirements from District III. In a sense, therefore, the District III crude oil production projections contain not only local requirements, but also final deficits in supply for Districts I and II after considering all other potential supply sources within the limits of the national model projections.

As in the national model, the projections of supply in the District models were assessed, as far as possible, within a range of outcome in the year 1985. Full consideration was given to different production expectations from the North Slope. Also, the effect of the range of crude oil imports in Case A and Case B of the national model was provided for by a range of production levels in those Districts with little excess productive capacity.

A. The District V Supply and Demand Model

Since the major new factor influencing the regional analysis is the production and disposition of crude oil from the North Slope of Alaska, the discussion will begin there. The District V model projection, shown on page 154, indicates that crude oil supply will be in excess of local requirements after 1975 and the surplus will probably increase toward 1985.

Crude oil requirements in District V are projected to be 2,054 MBD in 1975 and 2,860 MBD in 1985, representing an average rate of growth of 3.8 percent per year from the base period 1965. A similar percentage gain in product demand is projected.[1]

Historically, a significant volume of imports of crude oil has entered District V, limited in recent years only by the mandatory control program. The advent of Cook Inlet production in Alaska has reduced the potential market available for imports, and a further reduction is foreseen. Because of the nature of the quality of these imported crudes to meet requirements of some of the refineries in the District, it is projected that as North Slope crude oil becomes available, imports will decline to a flow of 100 MBD and remain at that volume throughout the forecast period.

To fulfill the remaining crude oil requirements a projection must first be made of production from areas within the District, exclusive of the North Slope. These include both onshore and offshore California and the Cook Inlet of Alaska. Production here has recently increased sharply, particularly

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[1] Projections of District product demand were developed using historical trends in per capita consumption and the Census population forecast series P-25, I–B, which are based on a continued westward migration through 1985.

because of Cook Inlet discoveries; more is expected from the California offshore areas. Onshore production, although periodically registering short periods of gain between declines, must be considered on a long-term downtrend. A review of industry estimates leads to the conclusion that production (excluding North Slope) in District V can best be expected to maintain a level of around 1,250 MBD for both 1975 and 1985.[1] This projection assumes increasing offshore California production essentially matching declines in other District V areas during the forecast period. Because some excess productive capacity is available now in District V, these production projections are not expected to vary under the conditions (Cases A and B) of alternative U.S. crude oil imports in 1985.

Turning now to the North Slope, as production comes onstream, it has been assumed that the first increments will flow within District V up to the level of available market, with the exception of the minimum import level. As discussed previously, three projections of North Slope production have been made—a "low" projection of 500 MBD, a "medium" projection of 750 MBD, and a "high" projection of 1,000 MBD in 1975. Each rate is assumed to triple by 1985 and all excess crude available is forecast to be transported to Districts I and II.

Under the "low" projection, as shown on page 154, all North Slope production will be used in District V and imports will remain above the minimum level. This means that by 1985, under the "low" projection, as much as 1,500 MBD of North Slope production will be required to satisfy crude oil requirements in District V under the assumed constraints. For the "medium" projection of North Slope production, a small flow of 76 MBD to Districts I and II is indicated by 1975, rising to 710 MBD in 1985. At such volumes it is anticipated that a pipeline of economical size will not be feasible until after 1980 into Districts I and II. Under the "high" projection, however, the timing of a pipeline will come much sooner. Under this projection approximately 1,500 MBD of North Slope production, about the same volume needed to meet the District V deficit, will be available in 1985 for transport to Districts I and II. The timing of a pipeline will be indicated by at least 1980, if not before.

Under all three sets of projections the deficit in crude oil supply in District V will be filled by North Slope production. Henceforth, it must be considered that the West Coast will no longer be considered deficient in petroleum supply, but rather will be an exporter of petroleum to other Districts within the U.S. Under the "medium" projection, it appears that these exports can not be made by a pipeline of economical size until the end of the forecast period. While under the "high" projection, the timing will be advanced by at least 5 years or 1980. Transportation of this excess production by tanker through the "Northwest Passage" or by other routes will, of course, allow lesser volumes to be moved at earlier dates.

Beyond 1985 it seems that North Slope oil to be used in District V will amount to the increasing deficit caused by incremental gains in product demand plus declines in production. At some point in time it is visualized that oil discoveries from newer offshore areas, such as the Gulf of Alaska, might tend to divert more North Slope oil to Districts I and II.

B. The District IV Supply and Demand Model

In the past the Rocky Mountains have provided a source of crude oil supply, above local requirements, to Middle West refineries and thus the area has been considered a surplus area. As illustrated on page 155, during the forecast period a somewhat similar situation is projected with some important limitations.

Growth in product demand, from 325 MBD in 1965 to 447 MBD in 1975 and 585 MBD in 1985, will necessitate the addition of a significant amount of local refining which would presumably have first call on district production. Terrain features, it is felt, would preclude the alternative of importation of products by pipeline. Because of these greater local requirements, movements of crude oil to District II are projected to decline from 340 MBD in 1965 to approximately 200 MBD by 1985.

A small volume of crude oil imports from Canada is brought into the Rocky Mountain area, representing to a degree the lack of certain high-gravity supplies. It is projected that by 1975 and continuing to 1985 about 50 MBD of these crudes will be imported. The District, however, is expected to continue being a surplus producing area.

To remain a surplus producing area, a major effort will be required to increase producing rates. The most recent exploratory efforts in the Rocky Mountains indicate that this is possible. Therefore, it is projected that a level of production from 660 to 728 MBD will be maintained from 1975 to 1985 under Case A. It is

[1] For example, see testimony of Chevron Standard Limited before the Alberta Oil and Gas Conservation Board (July 17, 1968) in the hearing on application for the so-called Syncrude tar sands plant.

understood that a number of older fields in this District will be on the decline during the period, but newer fields, exemplified by recent discoveries of the Belle Creek and Recluse fields, will maintain and slightly increase the District's producing rate.

If these production expectations cannot be maintained, then a higher level of crude oil imports will be required in 1985 under the Case B situation, and District IV production will be reduced to 628 MBD, or a return to the 1965 level. Crude oil imports as a result would be expected to increase proportionately to 150 MBD in 1985.

The Rocky Mountain area, therefore, is projected to continue to supply some excess crude oil above local requirements, but by 1985 will play only a minor role in meeting the supply deficits in Districts I and II. No consideration is given here to production of synthetic crude oil from oil shale during this time. This is not to say that toward the end of the century this possibility might not occur, but rather the model analysis indicates no imminent need under projected supply and demand conditions.

C. The Districts I and II Supply and Demand Model

Approximately two-thirds of the demand for petroleum in the United States is found in the states encompassed by Districts I and II (the East Coast and Middle West). This large consuming region has been historically and will continue to be deficient in local crude oil supplies and thus is the center of attention for any regional analysis. The table on page 153 illustrates in some detail the essential features of the petroleum supply and demand in these Districts for 1965 with projections for 1975 and 1985.

Although product demand is large, the necessary crude oil requirements to supply this demand are much less. This is because petroleum supply, to a larger extent, comes from products shipped into it, not from crude oil refined within the area. In 1965 only 48.7 percent of the area's demand was supplied through local refineries; this percentage is projected to decline to 41.4 percent by 1985. Essentially, the remaining supplies come from products shipped from other Districts and from imports, largely residual fuel oil. In 1965 slightly over 2,500 MBD of products were received from other Districts, or 33 percent of product demand. By 1985 this volume of shipments from other U.S. Districts is projected to reach 4,5000 MBD, a similar proportion (32 percent) of demand.

Product imports from foreign countries are expected to increase from slightly over 1,000 MBD in 1965 to approximately 1,700 MBD in 1975, a figure already approached in 1968. However, this recent growth is expected to slacken during the next 6 years during the period of market adjustment to sulfur limitations imposed by air pollution restrictions. After 1975, in Case A, however, another substantial surge in product imports is expected, at an annual rate of 4.2 percent, to reach a level of 2,640 MBD by 1985. This projection is made with the assumption that heavy fuel oil, after adjusting its competitive stance with regard to the sulfur problem, will compete vigorously in the utility and commercial heating markets after 1975, consistent with its performance in the period since 1965.[1]

If this should not occur, that is, residual fuel oil cannot maintain its market share vis-a-vis competitive fuels during this period, a slackening of imported products will occur, as shown in Case B, and a corresponding downward adjustment of total product demand of 600 MBD in Districts I and II will obtain below the projected volume of 14,032 MBD in 1985 under Case A. This difference in demand will not affect crude oil requirements since these products are refined in foreign areas.

The projected crude oil requirements in Districts I and II of 5,807 MBD in 1985 will come from four main sources–(1) local production; (2) imports; (3) the North Slope; (4) District II, and to a lesser extent District IV. As shown on page 153, it is necessary to express the contribution of each of these supply sources within a range dependent upon the several levels of North Slope projections as well as the alternative Cases A and B of imports.

A decline in crude oil production within Districts I and II is projected throughout the forecast period. The area's fields are essentially all in the mature stage of production with secondary and now tertiary recovery processes providing substantial contributions to current output. Improved techniques must be anticipated and, with this in mind, it is projected in Case A that until 1985 Districts I and II production will still be 1,147 MBD, a decline of approximately 200 MBD from the 1965 level.

In Case B crude oil production is projected to decline much more rapidly, to 767 MBD in 1985 or a decline rate of 2.7 percent per year. This figure is in general agreement with the recent production projection by Hall of Ashland Oil in reviewing the

[1] Recent approval for three "desulfurization plants" by the U.S. Government through licensing of 10-year import quotas indicates that the probability of Case A is now enhanced. *The Oil and Gas Journal,* January 27, 1969, page 91.

Midwest crude oil supply outlook.[1] It is difficult to evaluate which of these production expectations in 1985—1,147 MBD or 767 MBD—is the more likely. However, the range does imply that for the future in Districts I and II an increasing reliance must be given to outside supplies.

Imports, of course, are already providing a substantial part of this supply and will continue to do so through the forecast period. As shown on page 153, from a level of 821 MBD in 1965 imports are projected to increase to slightly over 1,300 MBD by 1975 and to a minimum level of 1,432 in 1985 under Case A, and to a maximum of 1,852 MBD under Case B, making up the difference of lesser local production cited above.

The next element of the crude oil supply is the movement of volumes from the North Slope. As previously explained, by 1975 under the "high" projection as much as 326 MBD can be expected to enter Districts I and II, while under the more pessimistic "low" projection all of this oil would remain in District V. By 1985, however, these movements would be much more substantial, ranging up to 1,460 MBD.

The final segment of Districts I and II crude oil requirements will come from the Southwest or District III. Here the full effect of North Slope production will be felt. As shown on page 153, there will be a need for 2,350 MBD to 1,844 MBD in 1975 of shipments from District III, the range between the "low" and "high" North Slope production projections, or a difference of 500 MBD. The spread will widen to 1,500 MBD by 1985. Looked at another way, under the "low" North Slope production projection District III shipments to Districts I and II will steadily increase to 3,025 MBD in 1985 from slightly under 1,400 MBD in 1965. Under the "medium" projection these shipments will plateau at around 2,275 MBD from 1975 and 1985, and under the "high" projection a reduction in volume will be experienced, from a level of 1,844 MBD in 1975 to about 1,525 in 1985.

Page 154 summarizes the preceding analysis of crude oil supply projections for Districts I and II. In 1965 local production and shipments from District IV amounted to 42 percent of crude oil requirements, followed by 36 percent from District III, and 22 percent from imports. By 1985 these proportions are expected to be sharply altered. North Slope production will supply as much as one-quarter of the region's need under the "high" projection, reducing the need for District III supplies from 53 percent to as low as 27 percent. Local District production will decline sharply to between 16 and 22 percent, and imports will slightly increase their relative position to between 25 and 32 percent.

[1] "A Midwest Refiner's View of Capline," John R. Hall, Ashland Oil and Refining Company, presentation to the NPRA Board of Directors, Pebble Beach, California, September 23, 1968.

D. The District III Supply and Demand Model

The supply and demand model for District III is much simpler to describe than those of other areas. Essentially it represents local requirements plus shipments to other districts. The essential elements of this model are shown on page 154.

Product demand in District III, which amounted to 1,775 MBD in 1965, is projected to grow by an annual average rate of 3.2 percent, reaching a level of 3,323 MBD in 1985. A large quantity of products, even greater in volume than the District demand, are projected to be transported to other districts. By 1985 these shipments are expected to reach 4,569 MBD.

By comparison, crude oil shipments to other districts are projected to increase much more slowly and possibly will decline after 1975 if the North Slope reaches the higher range of expectation. In numbers, as shown on page 154, by 1985 crude oil shipments to other districts will range from a high of 3,025 MBD to a low of 1,525 MBD, only marginally above the volume in 1965.

Nevertheless, the impetus of local requirements will be enough to sustain a continued growth in crude oil production. By 1975 production is projected to a range of 6,350 to 6,850 MBD, compared to 4,944 MBD in 1965. And after 1975 a further increase in production is projected to a range of 7,467 MBD to 8,967 MBD. In other words, no declines in District III production are foreseen even under the most optimistic rates from the North Slope.

E. Projection of Crude Oil Production from The OCS: The Regional Impact

Section IV-E points out that at the national level the rate of increase in new reserves of crude oil in the OCS will exceed that for new supplies onshore, excluding the North Slope. Because of this it is projected that production in the OCS will increase between 1967 and 1985 at a rate of approximately 7.3 percent per year, reaching a volume of about 2,500 MBD in 1985. This projection was buttressed by the conclusion that profitability of crude oil is higher in the OCS compared to onshore areas. It was further ascertained that on the basis of a Gompertz analysis there would be no difference in the future

level of OCS production from the Gulf of Mexico because of a "low" or a "high" projection of output from the North Slope, although the same was not indicated for the California OCS.

The essential point to determine in relation to these projections is whether or not they are realistic at the regional level, particularly in District III, with the expectations of continued production from District III onshore areas. A view has been expressed that the outlook for these onshore areas in District III has been lessened by the success of offshore exploration and more recently by the North Slope discovery.[1] The following analysis indicates that such discouragement is not warranted.

To derive the expected production of onshore areas in District III, it is necessary to fully consider the magnitude of expected crude oil requirements through the year 1985. As shown in table on page 155, by 1985 this quantity will be as high as 8,967 MBD under the "low" projection of production from the North Slope. Subtracting the expected production from the Gulf of Mexico of 2,050 MBD at that time leaves a need from onshore areas of 6,917 MBD, considerably above the volume of 5,084 MBD projected for 1970 or the expected volume of 5,630 MBD in 1975.

Even under the most optimistic expectations for the North Slope, the production from onshore areas to meet District III crude oil requirements is expected to increase toward 1985, although at a very low rate, as illustrated in table on page 155. While this eventuality is not certain, it would be no worse than the experience of the early 1960's when onshore production remained essentially constant. Therefore, the impact of the OCS projections with regard to onshore is that production onshore will remain essentially stable after 1970, while a gradual increase of around 2 percent per year can be anticipated under the lower North Slope production expectations.

From this report the important conclusion is that, under the assumed three alternative levels of North Slope producing rates, there are ample remaining crude requirements to be fulfilled by a growing volume of offshore oil production in the Gulf of Mexico. The outlook for production from OCS waters in California, while promising in the near-term to 1975, is dependent thereafter on developments on the North Slope, as well as the resolution of current problems of assured production techniques to prevent pollution of adjacent waters and environment. Finally, production from onshore areas in District III is projected to do no worse than maintain its present level, giving full allowance for increasing supplies from the North Slope and the OCS.

[1] See "Slope's Impact on U.S. Oil Seen Vast," *The Old and Gas Journal*, December 9, 1968, page 55.

VI. Some Implications Regarding Supplies of Petroleum Over The Period 1985 to 2000

As set out in Chapter A, the demand for petroleum is projected to continue to increase beyond 1985 and to the year 2000. Assuming no revolutionary technological change in our energy system, petroleum demand in the year 2000 is forecast as in the proximity of 10.4 billion barrels per year, compared with 7.8 billion barrels as of the year 1985.

There would seem to be a promising array of supply combinations which could, in net balance, provide a petroleum supply sufficiency over the 15-year period from 1985 to the year 2000. These alternate supplies could emanate from some combination of at least nine sources:

1. Continued importation of petroleum products and crude oil. If petroleum imports are held to 20 percent of the demand, then approximately 2.1 billion barrels would be imported in the year 2000, leaving some 8.3 billion barrels to be supplied from other sources.
2. Natural gas liquid production could continue to increase, at a rate depending in large degree upon natural gas production which will occur over the forecast period.
3. Some continued developments can be expected to take place in refinery design and utilization with a commensurate reduction in crude oil requirements.
4. The Gulf of Mexico potentially could continue to yield a substantial increase in production over and above the 750 million barrels estimated for the year 1985. To reach this 1985 production forecast, approximately 19 billion barrels would need to be found in the Gulf of Mexico, only 32 percent of the 60 billion barrels estimated by McKelvey to be economically recoverable.
5. Ultimate economic supplies in the North Slope could continue to increase, especially if reserves exceed the 30 billion barrels assumed as a maximum case by 1985.
6. The Alaska OCS has a substantial potential which, if commercial, could add momentum to the northern play which commenced with the Alaskan North Slope and now extends into

Canada. A northern oil center of magnitude could restructure supply patterns on an international scale.

7. The Atlantic OCS with its strategic location will be produced when and if commercially available.

8. Continued production of other onshore domestic supplies can reasonably be expected, perhaps following the Department of Interior projection which envisions further improvements in recovery rates.

9. Synthetic petroleum produced from domestic supplies of oil shale, oil sands, and coal may be introduced into the supplies of petroleum in the United States.

In considering the possible combinations of these nine sources, it seems reasonable to speculate that: first, sufficient supplies are likely to be forthcoming to meet domestic demands to the year 2000; second, the U.S. Outer Continental Shelf has an important role in supplying these demands; and, third, there will be a considerable restructuring of supply sources fulfilling petroleum demand over the 33-year period from 1967 to 2000.

APPENDICES

APPENDIX 1

SUMMARY OF OTHER RECENT PROJECTIONS

Title: **Future Natural Gas Requirements of the United States**

Author: Future Requirements Committee; Under the Auspices of the Gas Industry Committee[1]

Date of Publication: June 1967

Forecast Summary:

U.S. Natural Gas Requirements by Class of Service

	Requirements (Trillion Cubic Feet)				Annual Growth Rates (Percent)		
	Actual	Projected					
	1961	1975	1985	1990	1961-1975	1975-1985	1985-1990
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Residential	3.3	5.7	7.4	8.3	4.0	2.6	2.3
Commercial	1.0	1.9	2.6	2.9	4.7	3.2	2.2
Firm Industrial	3.7	7.6	9.2	10.3	5.3	1.9	2.3
Interruptible	2.8	4.9	5.9	6.4	4.1	1.9	1.6
Field Use[a]	1.9	3.1	4.0	4.7	3.6	2.6	3.3
Other[b]	1.1	2.3	2.9	3.4	5.4	2.3	3.2
Total	13.8	25.5	32.0	36.0	4.5	2.3	2.4

[a] Includes lease pumping, drilling, plant extraction loss, and fuel.

[b] Includes pipeline fuel, company use, unaccounted for, transmission loss, and any other sale or actual use not otherwise specified.

Note: Natural gas demand forecasts are also shown for the U.S. divided into ten regions.

Major Assumptions: (Forecasts are composites of forecasts made by individual utilities throughout the United States.)

GNP: Each utility used its own forecast of the GNP growth within its service area.

Population: Each utility used its own forecast of population growth within its service area.

Industrial Production: Each utility used its own forecast of industrial growth within its service area.

[1] Published by the Future Requirements Agency, Denver Research Institute, University of Denver, Denver, Colorado.

Supply Availability:	Each utility was asked to base its forecast on the assumption there would be an adequate supply of gas for all estimated requirements in its market area for all periods covered by the survey.
Fuel Prices:	Each utility was asked to base its forecast on the assumption the present-day relationship of the cost of gas to the cost of competing fuels would remain the same in the future.
Other:	Other factors taken into consideration by the individual utilities included household formations, new construction, normal U.S. Weather Bureau degree days and appliance saturations.
Methodology:	The United States is divided into 10 regions and regional work committees established. The utilities in each region were asked to submit "actual" volumes for the years 1961-1965; "estimated" requirements for 1966-1970 and for 1975; "projected" requirements for 1980, 1985, and 1990. Regional work committees then evaluated each utility's data and estimated requirements of non-reporting utilities. The regional work committees' data were then reviewed by the Future Requirements Committee and combined into a national report. The national report was next reviewed by the Future Requirements Agency, Denver Research Institute of the University of Denver, who published the final document.

Title:	**An Energy Model for the United States, Featuring Energy Balances for the Years 1947 to 1975 and Projections and Forecasts to the Years 1980 and 2000; U.S. Bureau of Mines Information Circular 8384.**
Authors:	Warren E. Morrison and Charles L. Readling, Bureau of Mines, U.S. Department of the Interior
Date of Publication:	July 1968
Forecast Summary:	See table on page App. 1-5.
Major Assumptions:	
GNP:	Low: 2.5% annual growth 1965-1980 Medium: 4.0% annual growth 1965-2000 High: 5.5% annual growth 1965-1980
Population:	Low: 1.0% annual growth 1965-1980 Medium: 1.6% annual growth 1965-2000 High: 2.2% annual growth 1965-1980
Industrial Production:	All forecasts: 4.4% annual growth 1965-1980 or 2000.
Supply Availability:	All forecasts: adequate supplies of energy resources, either domestic or imported, to meet projected demand. Synthetic liquid fuels are expected to begin supplementing conventional liquid fuels within the next 15 years. Coal and oil shale gasification are expected to be supplying small amounts by 1980, but these are not expected to be a significant portion of energy supply by 1980.
Fuel Prices:	All forecasts: assume stability of real costs of primary energy sources relative to each other.
Federal Government's Energy Policy:	All forecasts: present policy is assumed as continuing unchanged to 1980.
Methodology:	A basic energy model is developed consisting of a series of equations that describe the relationships between various determining variables that influence energy on the one hand, and the dependent variable of total energy demand and its major subcomponents on the other. The model uses single and multiple correlations to relate dependent and independent variables. Many independent variables are considered but only three are quantified for use in the model; economic activity (GNP), population and index of industrial production. Different combinations of these variables are put into the model to calculate energy demands under different economic conditions. A technological forecasting technique, sometimes called contingency forecasting, is used to make the forecasts to the year 2000. Contingency situations are envisioned for the forecast year wherein major technological innovations completely displace the conventional energy system. A base case assuming continuation of the present conventional energy system to the year 2000 is developed. The first contingency envisages a hydrocarbon-air fuel-cell energy system to be used for on-site generation of power and heat recovery with no purchased utility electricity in 2000, while a second contingency envisages an all-electric economy supplied by utility electricity.

FORECAST SUMMARY:

Domestic Demand1/

	Requirements (Quadrillion Btu)					Annual Growth Rate (Percent)			
	Actual	Projected 1980			Projected 20002/	Projected 1965-1980			Projected 1980 - 20002/
	1965	Low	Medium	High	Medium	Low	Medium	High	Medium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Petroleum3/	23.2	30.2	36.0	42.8	57.6	1.8	3.0	4.2	2.4
Gas	16.1	21.3	25.4	30.1	41.7	1.9	3.1	4.3	2.5
Coal	12.4	16.5	19.6	23.3	20.7	1.9	3.1	4.3	0.3
Water Power	2.0	2.5	3.0	3.6	5.1	1.5	2.7	4.0	2.7
Nuclear	0.1	3.4	4.1	4.9	43.5	26.5	28.1	29.6	12.6
Total Domestic Demand	53.8	73.9	88.1	104.7	168.6	2.1	3.3	4.5	3.3

1/ Demands by energy consumers.

2/ Excluding raw material usage.

3/ Including NGL.

Title: The Changing Energy Picture and Its Impact on the Role of the Landman

Author: J. D. Moody, Senior Vice President, Mobil Oil Corporation

Date of Publication: June 12, 1968

Forecast Summary:

Total U.S. Energy Consumption

	Requirements (Quadrillion Btu[1])			Annual Growth Rate (Percent)	
	Actual		Projected	1948-1968	1968-1988
	1948	1968	1988		
	(1)	(2)	(3)	(4)	(5)
Petroleum	11.4	24.8	40.8	4.0	2.5
Natural Gas	4.7	18.5	28.0	7.1	2.1
Coal	13.8	12.4	21.3	-0.5	2.7
Water Power	1.2	2.2	3.2	3.1	1.9
Nuclear		0.2	20.5		26.0
Total	31.1	58.1	113.8	3.2	3.4

[1] Converted from MMBbls/d oil equivalents.

Major Assumptions: No assumption stated relating to the future growth of the economy.

Supply Availability: Forecast does not comprehend any gasification of coal, but does assume petroleum will come from non-conventional sources.

Technological Developments: Problems facing coal as the result of sulfur emission controls will be largely overcome by 1988.

Methodology: Not described.

Title: **Ebasco's Annual Forecast of Energy Consumption in the U.S.**

Author: Ebasco Services, Incorporated

Date of Publication: December 26, 1967

Forecast Summary:

Energy Consumption

	Requirements (Quadrillion Btu)			Annual Growth Rate (Percent)	
	Actual	Projected			
	1965	1975	1985	1965-1975	1975-1985
	(1)	(2)	(3)	(4)	(5)
Natural Gas Liquids	1.9	3.1	4.1	5.0	2.8
Crude Oil and Net Petroleum Product Imports	21.6	28.7	35.7	2.9	2.2
Gas	16.1	25.1	31.5	4.5	2.3
Coal	12.4	16.2	20.0	2.7	2.1
Water Power	2.0	2.6	3.2	2.7	2.1
Nuclear	n/	4.3	15.5	--	13.7
Total	54.0	80.0	110.0	4.0	3.2

n/ Less than 0.05 quadrillion Btu.

Major Assumptions:

Population: 1.4% annual growth 1965-1975; 1.7% annual growth 1975-1985.

Note: No other assumptions given.

Methodology: Per capita energy consumption is projected to 1975 and 1985. These projections are then multiplied by the 1975 and 1985 population levels, as forecast by the U.S. Bureau of Census to obtain total energy consumption in those years. Total energy consumption is then allocated to the different types of fuels.

Title: **Competition and Growth in American Energy Markets, 1947-1985**

Author: Texas Eastern Transmission Corporation

Date of Publication: January 1968

Forecast Summary:

Energy and Fuel Consumption1/

	Requirements (Quadrillion Btu)			Actual Growth Rate (Percent)	
	Actual	Projected			
	1965	1975	1985	1965-1975	1975-1985
	(1)	(2)	(3)	(4)	(5)
Petroleum2/	23.7	33.8	47.6	3.6	3.5
Gas	16.2	26.1	38.7	4.9	4.0
Coal	11.7	16.6	23.1	3.6	3.4
Water Power	0.7	0.9	1.3	2.5	3.7
Nuclear	n/	2.2	8.8		14.9
Total Energy and Fuel Consumption	52.3	79.6	119.5	4.3	4.1

1/ Total requirements including non-energy uses and losses.
2/ Including NGL.

n/ Less than 0.05 quadrillion Btu.

Major Assumptions:

GNP: 5.1% annual growth 1965-1975; 4.9% annual growth 1975-1986.

Population: 1.2% annual growth 1965-1975; 1.4% annual growth 1975-1985.

Industrial Production: 5.1% annual growth 1965-1975; 4.5% annual growth 1975-1985.

Supply Availability: Sufficient supplies of fuels available. Assumes that U.S. can draw upon foreign supplies and that technology will be developed to change energy from one form to another, i.e., gasification of coal.

Fuel Prices: Continuation of the general price trends that have developed between energy sources in the various markets.

Technological Developments: (See supply availability.) Absence of extraordinary technological developments.

Methodology: "Energy requirement" synonymous with "end-use requirement", is forecast to 1985. "End-use requirement" is measured at the point of final consumption and is the aggregate need for heat, cooling and power that evolves from both the level of economic activity and population. Future requirements for specific energy forms, gas, coal, etc., are then developed, based upon energy requirements, non-energy uses of fuels and losses.

Title: U.S. Demand for Atomic and Conventional Energy by 1982, a 15-Year Forecast with Emphasis on Petroleum

Author: John H. Lichtblau, Research Director, Petroleum Industry Research Foundation, Inc.

Date of Publication: October 27, 1966

Forecast Summary:

Total Domestic Energy Demand

	Requirements (Quadrillion Btu) Actual 1966	Requirements (Quadrillion Btu) Projected 1982	Actual Growth Rate (Percent) 1966-1982
	(1)	(2)	(3)
Petroleum	22.5	34.2	2.7
Natural Gas Liquids	2.0	3.7	3.9
Natural Gas	16.8	29.8	3.6
Coal	13.0	16.5	1.5
Water Power	2.1	2.6	1.3
Nuclear	0.1 a/	9.8	33.2
Total	56.5	96.6	3.4

a/ Overstated in 1966 because of rounding.

Major Assumptions:

GNP: 3.3% annual growth 1967-1982.

Population: 1.4% annual growth 1967-1982.

Housing Construction: 2.25 million dwelling units annually 1967-1982.

Fuel Prices: Cost of atomic energy will continue to decline both in real terms and relative to conventional fuels.

Technological Developments: No major commercial impact from technological developments except in the case of nuclear power.

Methodology: Total U.S. energy demand is projected to 1982, based on projected growths of significant economic indicators including GNP, population, etc. The electric utility portion of this total demand is then projected and electric utility fuel requirements developed. The transportation, residential and commercial and industrial fuel requirements are then forecast to 1982.

Title:	**Total Energy Picture**
Source:	Panel Discussion at the Opening Session of the 1968 American Mining Congress Coal Convention in Pittsburgh, Pennsylvania
Date of Publication:	May 6, 1968

Mr. B. R. Dorsey, President, Gulf Oil Corporation, represented the oil industry in this panel discussion of the future energy picture. The following table summarizes his projections for 1975 and 1985.

	(Quadrillion Btu)	Annual Growth Rates (Percent)	
	1975	1965-1975	1975-1985
	(1)	(2)	(3)
Liquid Petroleum	35.7	3.0	2.5
Natural Gas	28.7	5.0	3.0
All Other Energy Sources	22.6		
Coal	13.9	1.5	1.5
Hydro[a]	3.5		
Nuclear	5.2	60.0	15.0
Total	87.0	3.9	3.5

[a] Hydro power is not mentioned by Mr. Dorsey, but is assumed at 3.5 quadrillion Btu in 1975 in order to make the total check.

Mr. Dorsey also discussed the changes in the energy mix that he anticipates in 1975 and 1985.

	Percent of Total Energy Demand[a]	
	1975	1985
Liquid Petroleum	41	36
Natural Gas	33	30
All Other Energy Sources		
Coal	16	13
Hydro[a]		
Nuclear	6	17
Synthetic Oils		5
Total Energy Demand	96	101

[a] Hydro power was not mentioned by Mr. Dorsey, but since the percentages given do not add to 100% one must assume they are only generalized and that hydro power will continue to add a nominal amount to the total energy picture.

Mr. Dorsey's projections are based on certain assumptions of demand by economic sectors. He expects the transportation sector to grow at the annual rate of 4 percent between 1965-1975 and 3 percent between 1975-1985. He assumes liquid petroleum will continue to dominate this sector of the economy.

The residential and commercial sector is expected to grow at the annual rate of 3.5 percent between 1965-1975 and 3 percent from 1975-1985. Liquid petroleum is expected to lose part of its current share of this market with natural gas continuing to gain in its share.

The industrial sector is expected to grow at a rate of 3 percent over the period 1965-1985, with coal maintaining about 25 percent of this market through 1975 and liquid petroleum losing some ground to natural gas. After 1975 coal is expected to gain part of the natural gas share of the industrial market, increasing its total share to 29 percent.

Nuclear power is expected to gain rapidly in the electrical sector holding coal to about 20 percent above the 1965 level. Liquid petroleum will continue to lose in this market, but natural gas probably will show some gains through 1975.

Title: **U.S. Energy and Petroleum Requirements for 1980**

Author: Pan American Petroleum Corporation

These statistics (among others) are referenced on page 5 of the U.S. Department of the Interior's study, *United States Petroleum Through 1980.* The Pan American Petroleum Corp. study apparently used a base year of 1965 or 1966 and projected the following requirements for 1980.

	Total Energy Requirements 1980 Quadrillion Btu	Percent of Total
Oil[1]	36.8	42.3
Gas[2]	29.0	33.3
All Other Sources	21.2	24.4
Total	87.0	100.0

[1] Equivalent to 18.6 million barrels per day converted at the rate of 5,400,000 Btu per barrel.

[2] Equivalent to 28 trillion cubic feet converted at the rate of 1,035 Btu per cubic foot.

Title: Hydrocarbons for the Future

Author: A. A. Draeger, Manager Corporate Planning Department, Humble Oil and Refining Company

Publication: Speech delivered before the Joint Meeting of the Commercial Chemical Development Association, Inc. and Chemical Marketing Research Association, Denver, Colorado, November 19, 1968.

Conclusions:

1) Total energy demand will grow at a rate of 3.5-4.0 percent per year.
2) The supply of hydrocarbons potentially available is enormous and a high degree of interchangeability exists among the sources of primary hydrocarbon supplies.
3) The available supplies of coal are abundant and a continued but modest growth will be achieved.
4) Natural gas supply will become an increasingly important consideration and some shifts in the potential markets to higher value usages is likely.
5) Oil supplies are projected to be fully adequate to meet projected demands.
6) Synthetics derived from oil shale and/or coal could enter the scene on a limited scale by 1980.
7) There is little doubt about the adequacy of total hydrocarbon supplies.

U.S. Energy Demand[a/]

	Demand (Quadrillion Btu) 1967	Demand (Quadrillion Btu) 1980	Annual Growth Rate 1967-1980 Percent
	(1)	(2)	(3)
Oil and Natural Gas Liquids	28.3	42.6	3.2
Natural Gas	20.2	32.8	3.8
Other Energy Sources	14.5	24.6	b/
Total	63.0	100.0	

a/ Demand by type of energy source computed from percentage distributions given for 1967 and growth rates given for 1967-1980.

b/ Annual growth rate for coal 2.0 percent; for hydro 2.2 percent; and for nuclear power 36.2 percent.

The demand projections were made by an analysis of the economic sectors. The transportation sector, dominated by petroleum is expected to grow at 4.0 percent annually. The industrial sector will have an annual growth rate of 3.4 percent and the residential and commercial sector a 3.9 percent annual increase.

Assumptions:

1) Real Gross National Product will grow at about 4 percent per year.
2) The economy will be regulated through monetary and fiscal policies to:
   a) Maintain full employment.
   b) Contain inflation.
   c) Manage the balance-of-payments problems.

3) Technological advances will occur at an increasingly rapid pace but will be generally evolutionary rather than revolutionary.

4) Regulatory actions, political factors, and responses to actions taken to solve social problems will influence business objectives and practices to an ever increasing degree.

5) Intra- and inter-industry competitive factors will be operative much as they are today.

APPENDIX 2

ASSUMPTIONS

No complete list of assumptions used in this report is given for the reason that it was procedurally more realistic to identify assumptions within the text as an integral part of the narrative to give fuller understanding of the development of methodology and analysis procedures. Therefore, the general economic assumptions are found in Chapter A, assumptions as to future supply and demand trends of natural gas are included throughout Chapter B, and similar assumptions for petroleum are referenced in Chapter C.

APPENDIX 3

U.S. REGIONAL GAS FLOW ANALYSIS 1967-1985

A Technical Report

To better understand the role of the Outer Continental Shelf in present and future movements of natural gas between producing areas and market regions, a regional analysis of natural gas was undertaken. As a starting point, the 1967 flows between ten domestic producing areas and ten market regions were estimated. Then several futures supply-demand cases were developed for the 1968-1985 period. The methods used and results obtained in what is considered the more probable of these cases are set out in this Appendix.

In general, the forecast of regional gas demands is consistent with demands set out in Chapter A, and regional supply projections are consistent with those projected in Chapter B.

Flows between conventional producing areas and the ten market regions were projected to 1985, using manual calculation procedures. When a producing area was no longer able to meet the projected demands, because of limited producing capacity, supply deficits were accrued in the market regions.

A linear transportation model was then used to help determine how these deficits might most economically be met by other gas sources, including OCS reserves out to 600 feet of water, deep reservior onshore gas, syngas, and LNG. This model, which is described in more detail later on, was designed to minimize the total cost of meeting these deficits, given the size of the deficits, supplies available from alternative supplemental sources, and their estimated delivered costs.

The results of alternative computer runs were then analyzed, taking into consideration institutional factors that could not be programmed into the linear transportation model, and conclusions drawn as to possible future demands for potential OCS gas production.

Data and Analytical Procedures

The 1967 flows between producing areas and market regions, as developed from published sources, were used as a starting point for this analysis. The results are summarized in the accompaning table, page 80.

Demand is defined to include end market and other gas uses,[1] less imported gas plus gas exported from a market region to a foreign country. In other words, demand is the requirement for U.S. produced gas.

Gas imports from Canada projected to 1975 and 1985 resulted from a special study described in more detail in Chapter B. Exports of U.S. gas to Canada and the flows between the U.S. and Mexico were extrapolated on the basis of past flows modified by institutional factors.

Additions to gas reserves were projected for each producing area based on the 1963-1967 or 1965-1967 trends in average annual reserve additions, modified by trends in exploration, well drilling, potential reserves, and other factors described more fully in Chapter B. Production in each area was projected to meet market requirements until the regional reserve-production ratio reached 12 years, at which point in time production was set at a rate to maintain that ratio. To test the potential impact of the Atlantic OCS, commercial production was arbitrarily assumed to commence after 1975, amounting to about 1.5 trillion cubic feet by 1985.

As to supplies of syngas, it was initially assumed that by 1980 there could potentially be a plant at each of several hypothetical locations producing 175 Bcf of pipeline quality gas annually. If the model utilized any plant's capacity, it was arbitrarily assumed that two more plants would be built by 1985 at that location.

As to supplies of LNG, it was initially assumed there potentially would be LNG plants in Boston and New York City having annual base load capacities ranging between 60 Bcf and 220 Bcf; and plants in the Los Angeles and San Francisco, California and Portland, Oregon areas having annual capacities ranging between 60 Bcf and 110 Bcf. Peak shaving use of LNG was not considered in this study.

A special study of the current art of stimulating gas reservoirs by nuclear explosion indicated no commercial supplies of any magnitude would be competitive with conventional supplies, without further technological and economical improvements.

Delivered costs of incremental gas supplies were used as a guide in directing certain flows calculated manually, and it was these delivered costs that the linear transportation model sought to minimize for the entire United States.

[1] Vented and flared, net to storage, and statistical discrepancy between USBM and AGA production data.

Delivered costs of domestic supplies are equal to an estimated field price plus an estimated cost of moving the gas to a load center in each market region, based on existing (1968) price-cost structures, adjusted upward by 10 percent to establish a range.

Transportation costs were calculated for feasible routes between producing areas and market regions. Each transportation route selected for the purpose of this analysis followed as far as possible existing pipelines. Distances were measured from major processing plants within each of the supply areas along existing lines, to a point of delivery within the market area, at present major delivery connections. Distances were measured from *The Oil and Gas Journal*, "Atlas of Natural Gas Pipelines in the United States and Canada", published September 20, 1965.

Unit costs of transmission were estimated according to the following table:

Pipe Size	Cents per Mcf per 100 Miles
16 inch	3.00
20 inch	2.60
24 inch	2.30
26 inch	1.94
30 inch	1.50
34 inch	1.40
36 inch	1.35

These cost data were derived from a study completed by Foster Associates, Inc. in 1964, which was based on several sources, and assumed an 85 percent load factor. A check made with the engineering department of a major gas transmission company indicated slightly lower unit costs than shown here. However, in view of rate increase applications filed by numerous pipeline companies, the tabulated data were considered prospectively reasonable.

In addition to the distance and unit costs shown above, rough estimates were made for certain added costs: 1.1 cents for piecemeal construction or looping; 1.2 cents for difficult terrain and, in a few cases, a factor of 1.3 cents was used for extremely difficult terrain or combinations of piecemeal construction and difficult going. A downward adjustment was also made for the prospective use of larger than 36-inch diameter pipe.

The estimated prices of syngas at the tailgate were based upon a special study of current literature on the subject.[1] Tailgate prices were estimated for medium-sized plants at seven hypothetical plan locations.[2] The cost of transporting the gas from the plants to market regions was estimated using the same procedures used for estimating other natural gas transportation costs.

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[1] See for example:

Consolidation Coal Company, *Pipeline Gas From Lignite Gasification*, Report 1, Project No. 180, Office of Coal Research Contract No. 14-01-0001-415, January 13, 1965.

Linden, Henry R. (Director, Institute of Gas Technology), "Coal Gasification and Natural Gas", *American Gas Journal*, April 1967, pp. 19-25.

Reichl, Eric H., *Liquefaction and Gasification of Coal*, presented during a symposium—An Assessment of Some Factors Affecting the Availability of Oil and Gas in the United States Through 1980, United States Department of the Interior, Washington, D.C., March 10, 1967.

Tsaros, C. L., and Joyce, T. J., *The Economics of Coal Hydrogasification*, presented at the American Gas Association, Inc., Synthetic Pipeline Gas Symposium, Pittsburgh, Pennsylvania, November 15, 1966.

[2] Western Pennsylvania, Northern West Virginia, Eastern Ohio, Southern Illinois, North Dakota, Eastern Kansas, and Northwestern New Mexico.

Delivered cost estimates of LNG were based on a special study prepared by Arthur D. Little, Inc.[1] expressed in a range to reflect economies of scale obtainable through the use of large plants.

A linear program was used to analyze the flows of supplemental gas to meet implied deficits in the market regions. The IBM application program, *Mathematical Programming System/360* (360A-CO-14x) *Linear Inseparable Programming* was used in this analysis. Based on this program, a linear programming model was constructed using transportation distances, transportation costs, and gas prices at the point of production as input factors.

The mathematical application of the programming approach in the present study was as follows:

Given: m supply areas, each given area A_i having capacity, represented by C_i, to meet demands; and n market areas, each given market M_j requiring aggregate supply sufficient to meet implied deficits represented by W_j

The portion of the implied deficit of M_j contributed by supply A_i is designated as x_{ij}

The effective distance from supply A_i to market M_j is given as d_{ij}

The cost per unit of demand transported a unit distance varies with the quantity transported, the larger the quantity, the lower the price. This transportation cost factor t is a function of x; that is, $t = T(x)$; but it will vary with every x_{ij} so that each will be associated with a particular value of the function t_{ij}. An arbitrary terrain factor was also introduced.

Model:

(1) Minimize $\sum_{i=1}^{m} \sum_{j=1}^{n} (p + td)x_{ij}$ (the objective function)

subject to the conditions that all implied deficits in each market M_j are met:

(2) $$\sum_{i=1}^{n} x_{ij} = W_j \text{ (structural constraint)}$$

and that no producing area A_i can deliver beyond its capacity:

(3) $$\sum_{j=1}^{m} x_{ij} \leqq C_i \text{ (structural constraint)}$$

(4) All x_{ij} to be positive (formal constraint)

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[1] A confidential report prepared for Foster Associates. See also an article by Bertrand de Frondeville, James T. Jensen and Kurt H. Wulff of Arthur D. Little, Inc., "Imports Complement Domestic LNG", *Pipe Line Industry*, October 1968.

REGIONAL SUPPLY AND DEMAND FOR NATURAL GAS IN THE UNITED STATES

1967

(Trillion Cubic Feet at 14.73 Psia)

	Consuming Regions										
Producing Areas	New England	Appalachian	Southeast	Great Lakes	Northern Plains	Mid-Continent	Gulf Coast	Rocky Mountain	Pacific Southwest	Pacific Northwest	Total Continental United States
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
South Louisiana (Including OCS)	0.1	1.9	0.8	0.8		0.1	1.6				5.3
Texas Gulf Coast (Including OCS)	0.1	0.6	0.2	0.5			2.3				3.7
Hugoton-Anadarko		0.1		0.9	0.6	1.0	0.3	0.1			3.0
Permian Basin					0.1		0.5		1.1		1.7
Other Southwest		0.2	0.2	0.1		0.5	1.4				2.4
San Juan Basin, New Mexico									0.5		0.5
Rocky Mountain					0.1			0.4		0.1	0.6
California									0.6		0.6
Appalachian and Other Areas		0.5									0.5
Total Domestic Production	0.2	3.3	1.2	2.3	0.8	1.6	6.1	0.5	2.2	0.1	18.3
Net Imports 1/					0.1				0.3	0.1	0.5
Total Requirements	0.2	3.3	1.2	2.3	0.9	1.6	6.1	0.5	2.5	0.2	18.8

1/ Net overland imports from Canada and Mexico.

ESTIMATED REGIONAL SUPPLY AND DEMAND FOR NATURAL GAS IN THE UNITED STATES

1975

(Trillion Cubic Feet at 14.73 Psia)

	Consuming Regions										
Producing Areas	New England	Appalachian	Southeast	Great Lakes	Northern Plains	Mid-Continent	Gulf Coast	Rocky Mountain	Pacific Southwest	Pacific Northwest	Total Continental United States
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
South Louisiana (Including OCS)	0.2	2.9	1.3	0.8	--	0.1	3.0	--	--	--	8.3
Texas Gulf Coast (Including OCS)	0.1	0.7	0.2	0.5	--	--	3.8	--	--	--	5.3
Hugoton-Anadarko	--	--	--	0.8	0.5	1.1	0.3	0.1	--	--	2.8
Permian Basin	--	--	--	0.7	0.5	0.2	0.5	--	1.5	--	3.4
Other Southwest	--	0.2	0.2	0.1	--	0.5	1.4	--	--	--	2.4
San Juan Basin, New Mexico	--	--	--	--	--	--	--	0.1	0.6	--	0.7
Rocky Mountain	--	--	--	--	--	--	--	0.4	--	0.1	0.5
California (Including OCS)	--	--	--	--	--	--	--	--	0.7	--	0.7
Appalachian and Other Areas	--	0.4	--	0.1	--	--	--	--	--	--	0.5
Total Domestic Production	0.3	4.2	1.7	3.0	1.0	1.9	9.0	0.6	2.8	0.1	24.6
Estimated Net Imports[1/]	--	--	--	0.2	0.1	--	--	0.1	0.5	0.3	1.2
Total Requirements	0.3	4.2	1.7	3.2	1.1	1.9	9.0	0.7	3.3	0.4	25.8

[1/] Estimated net overland imports from Canada and Mexico.

ESTIMATED REGIONAL SUPPLY AND DEMAND FOR NATURAL GAS IN THE UNITED STATES

1985

(Trillion Cubic Feet at 14.73 Psia)

Producing Areas	Consuming Regions: New England	Appalachian	Southeast	Great Lakes	Northern Plains	Mid-Continent	Gulf Coast	Rocky Mountain	Pacific Southwest	Pacific Northwest	Total Continental United States
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
South Louisiana (Including OCS)	0.3	2.5	1.3	1.7	--	0.2	5.2	--	--	--	11.2
Texas Gulf Coast (Including OCS)	0.1	0.7	0.2	0.5	--	0.2	5.1	--	--	--	6.8
Hugoton-Anadarko	--	--	--	0.7	0.6	1.1	0.3	0.1	--	--	2.8
Permian Basin	--	--	--	0.5	0.6	0.3	0.5	--	1.5	--	3.4
Other Southwest	--	0.2	0.2	0.1	--	0.5	1.4	--	--	--	2.4
San Juan Basin, New Mexico	--	--	--	--	--	--	--	0.3	0.4	--	0.7
Rocky Mountain	--	--	--	--	--	--	--	0.4	--	0.1	0.5
California (Including OCS)	--	--	--	--	--	--	--	--	1.0	--	1.0
Appalachian and Other Areas (Including Atlantic OCS)1/	--	1.2	0.7	0.1	--	--	--	--	--	--	2.0
Total Domestic Production	0.4	4.6	2.4	3.6	1.2	2.3	12.5	0.8	2.9	0.1	30.8
Estimated Net Imports2/	0.1	0.9	--	0.8	0.2	--	--	0.1	1.3	0.6	4.0
Total Requirements	0.5	5.5	2.4	4.4	1.4	2.3	12.5	0.9	4.2	0.7	34.8

1/ Assumed gas production in the Atlantic OCS is for the purpose of illustration. If a lesser amount of gas is produced in the Atlantic, more LNG imports or synthetic coal will be required on the East Coast and vice versa.

2/ Estimated combination of net overland imports from Canada and Mexico, liquefied natural gas and/or gasification of domestic coal.

APPENDIX 4

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES OF NATURAL GAS BY PRODUCING AREAS

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

SOUTH LOUISIANA[a]

1956-1967

(Volumes in Billions of Cubic
Feet at 14.73 Psia)

Year	Reported Data		Ratio of New Supply to Net Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[b]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	4,349	1,393	3.1		39,333	28.2
1957	7,902	1,587	5.0	3.6	45,647	28.8
1958	5,222	1,821	2.9	3.6	49,048	26.9
1959	7.192	2,254	3.2	2.8	53,986	24.0
1960	6,228	2,488	2.5	2.5	57,726	23.2
1961	5,415	2,771	2.0	2.5	60,370	21.8
1962	9,171	2,979	3.1	2.4	66,563	22.3
1963	7,226	3,352	2.2	2.4	70,437	21.0
1964	6,957	3,513	2.0	2.0	73,880	21.0
1965	7,798	4,008	1.9	1.7	77,670	19.4
1966	5,510	4,566	1.2	1.5	78,613	17.2
1967	8,181	5,371	1.5		81,424	15.2

a/ Includes offshore.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

PERMIAN BASIN[a/]

1956-1967

(Volumes in Billions of Cubic
Feet at 14.73 Psia)

Year	Reported Data		Ratio of New Supply to Net Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[b/]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	2,963	1,364	2.2		23,632	17.3
1957	912	1,353	0.7	1.5	23,189	17.2
1958	2,173	1,327	1.6	1.1	24,034	18.1
1959	1,355	1,317	1.0	1.1	24,070	18.3
1960	1,066	1,351	0.8	0.7	23,782	17.6
1961	374	1,374	0.3	0.4	22,779	16.6
1962	149	1,357	0.1	0.5	21,569	15.9
1963	1,604	1,324	1.2	1.2	21,835	16.5
1964	3,479	1,541	2.3	1.9	23,773	15.4
1965	3,634	1,606	2.3	2.5	25,799	16.1
1966	5,124	1,680	3.1	2.6	29,239	17.4
1967	4,322	1,689	2.6		31,869	18.9

a/ Texas Railroad Commission District Nos. 7C, 8 and 8A (West Texas) and Southeast New Mexico.

b/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

TEXAS GULF COAST[a]

1956-1967

(Volumes in Billions of Cubic Feet at 14.73 Psia)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	7,100	2,550	2.8		62,617	24.6
1957	3,134	2,561	1.2	1.7	63,190	24.7
1958	2,633	2,607	1.0	1.8	63,215	24.2
1959	8,738	2,691	3.2	1.6	69,263	25.7
1960	1,671	2,920	0.6	1.8	68,014	23.3
1961	5,017	2,910	1.7	1.3	70,121	24.1
1962	4,571	3,034	1.5	1.4	71,658	23.6
1963	3,328	3,175	1.0	1.1	71,811	22.6
1964	2,283	3,289	0.7	1.0	70,805	21.5
1965	4,376	3,457	1.3	1.0	71,725	20.7
1966	3,812	3,611	1.1	1.1	71,926	19.9
1967	3,343	3,679	0.9		71,592	19.5

a/ Texas Railroad Commission District Nos. 2, 3 and 4 and Offshore Texas.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

HUGOTON-ANADARKO[a]

1956-1967

(Volumes in Billions of Cubic
Feet at 14.73 Psia)

Year	Reported Data		Ratio of New Supply to Net Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[b]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	3,051	1,881	1.6		46,386	24.7
1957	2,815	1,884	1.5	1.7	47,323	25.1
1958	3,698	1,820	2.0	1.5	49,201	27.0
1959	2,218	1,999	1.1	1.2	49,432	24.7
1960	1,117	2,045	0.5	0.6	48,525	23.7
1961	683	2,176	0.3	0.5	47,031	21.6
1962	1,700	2,244	0.8	0.5	46,495	20.7
1963	1,102	2,406	0.5	0.7	45,192	18.8
1964	2,314	2,582	0.9	0.6	44,957	17.4
1965	1,272	2,687	0.5	0.6	43,548	16.2
1966	1,388	2,862	0.5	0.6	42,069	14.7
1967	2,329	3,002	0.8		41,396	13.8

a/ State of Kansas, Texas Railroad Commission District No. 10 and 21 counties in Oklahoma Panhandle Area.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES OF NATURAL GAS

OTHER SOUTHWEST[a]

1956-1967

(Volumes in Billions of Cubic Feet at 14.73 Psia)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	1,556	2,210	0.7		27,189	12.3
1957	3,106	2,444	1.3	1.2	27,869	11.4
1958	3,661	2,325	1.6	1.3	29,205	12.6
1959	2,352	2,460	1.0	1.3	29,113	11.8
1960	3,342	2,450	1.4	1.1	30,034	12.3
1961	2,410	2,336	1.0	1.1	30,103	12.9
1962	2,183	2,298	0.9	1.0	30,013	13.1
1963	2,731	2,472	1.1	1.2	30,290	12.3
1964	3,360	2,424	1.4	1.1	31,239	12.9
1965	2,301	2,415	1.0	1.1	31,135	12.9
1966	2,245	2,528	0.9	0.8	30,896	12.2
1967	1,041	2,426	0.4		29,582	12.2

a/ Texas Railroad Commission District Nos. 1, 5, 6, 7-B and 9, North Louisiana, Mississippi, Arkansas and Oklahoma, other than the 21 Panhandle counties which were included in Hugoton-Anadarko.

b/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

SAN JUAN BASIN, NEW MEXICO[a]

1956-1967

(Volumes in Billions of Cubic
Feet at 14.73 Psia)

Year	Reported Data		Ratio of New Supply to Net Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[b]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	4,120	197	20.9		15,842	80.4
1957	(45)	317		4.6	15,480	48.8
1958	(388)	285			14,807	52.0
1959	(2,877)	307			11,623	37.9
1960	(1,241)	350			10,032	28.7
1961	78	335	0.2		9,775	29.2
1962	(44)	312		1.0	9,419	30.2
1963	947	312	3.0	1.3	10,054	32.2
1964	501	432	1.2	1.6	10,123	23.4
1965	465	466	1.0	0.7	10,122	21.7
1966	5	509	c/	0.9	9,618	18.9
1967	945	532	1.8		10,031	18.9

a/ Northwest New Mexico.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

c/ Less than 0.05.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS

ROCKY MOUNTAIN[a]

1956-1967

(Volumes in Billions of Cubic
Feet at 14.73 Psia)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	830	313	2.7		7,556	24.1
1957	1,080	387	2.8	2.8	8,256	21.3
1958	1,068	365	2.9	2.7	8,958	24.5
1959	1,019	421	2.4	1.9	9,560	22.7
1960	208	437	0.5	1.7	9,348	21.4
1961	1,066	490	2.2	1.0	9,923	20.3
1962	82	449	0.2	0.9	9,585	21.3
1963	159	450	0.4	0.1	9,321	20.7
1964	(46)	478		0.3	8,812	18.4
1965	351	525	0.7	0.3	8,656	16.5
1966	207	561	0.4	0.7	8,335	14.9
1967	648	532	1.2		8,465	15.9

a/ Colorado, Montana, Nebraska, North Dakota, Utah and Wyoming.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NEW PRODUCTION AND TOTAL RESERVES OF NATURAL GAS

CALIFORNIA

1956-1967

(Volumes in Billions of Cubic Feet at 14.73 Psia)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[a]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	333	485	0.7		8,704	17.9
1957	657	469	1.4	1.0	8,904	19.0
1958	433	434	1.0	0.9	8,918	20.5
1959	95	463	0.2	0.9	8,547	18.5
1960	716	498	1.4	1.1	8,796	17.7
1961	781	536	1.5	1.3	9,054	16.9
1962	581	543	1.1	1.0	9,121	16.8
1963	332	614	0.5	1.0	8,866	14.4
1964	814	638	1.3	0.8	9,054	14.2
1965	387	622	0.6	0.8	8,832	14.2
1966	366	691	0.5	0.4	8,474	12.3
1967	(116)	641			7,724	12.0

[a] Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

APPENDIX 5

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL BY PAD DISTRICTS AND MAJOR PRODUCING STATES

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a/]

P.A.D. I [b/]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[c/]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	56.0	13.2	4.2		226.1	17.1
1957	3.5	13.1	0.3	1.7	216.6	16.5
1958	1.7	10.6	0.2	0.2	207.7	19.6
1959	1.6	10.3	0.2	0.2	199.0	19.3
1960	2.4	10.0	0.2	0.1	191.4	19.1
1961	(0.8)	10.0		0.2	180.6	18.1
1962	5.8	10.4	0.6	0.2	176.0	16.9
1963	1.4	9.9	0.1	0.3	167.5	16.9
1964	1.7	10.3	0.2		158.9	15.4
1965	(5.1)	10.0		0.1	143.9	14.4
1966	5.0	9.7	0.5	0.2	139.2	14.4
1967	4.8	9.9	0.5		134.1[d/]	13.5

a/ Excludes lease condensate.

b/ Excludes Florida and Virginia which are not given separately.

c/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 102.9 million barrels in 1967; increasing the RPR to 23.9 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

P. A. D. II[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply of Production: Annual	Ratio of New Supply of Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	556.9	493.5	1.1		4,295.7	8.7
1957	380.8	489.1	0.8	0.9	4,187.4	8.6
1958	413.1	475.4	0.9	0.9	4,125.1	8.7
1959	539.6	485.8	1.1	0.9	4,178.9	8.6
1960	396.2	480.5	0.8	0.9	4,094.6	8.5
1961	400.4	479.8	0.8	0.8	4,015.2	8.4
1962	343.3	488.4	0.7	0.7	3,870.1	7.9
1963	283.6	474.5	0.6	0.7	3,679.1	7.8
1964	362.3	482.7	0.8	0.7	3,558.7	7.4
1965	341.6	475.3	0.7	0.7	3,424.9	7.2
1966	358.2	476.8	0.8	0.7	3,306.3[d]	6.9
1967	252.9	468.0	0.5		3,091.2[d]	6.6

a/ Excludes lease condensate.

b/ Excludes Missouri, South Dakota and Tennessee which are not given separately.

c/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 775.2 million barrels in 1966 and 697.4 million barrels in 1967; increasing the RPR to 8.6 in 1966 and 8.1 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

P. A. D. III[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	1,775.9	1,504.8	1.2		20,017.5	13.3
1957	1,447.1	1,521.2	1.0	1.1	19,943.4	13.1
1958	1,409.0	1,356.9	1.0	1.3	19,995.5	14.7
1959	2,724.0	1,437.5	1.9	1.3	21,282.0	14.8
1960	1,518.1	1,430.2	1.1	1.4	21,369.9	14.9
1961	1,680.8	1,462.0	1.1	1.0	21,588.7	14.8
1962	1,387.6	1,504.1	0.9	1.0	21,472.2	14.3
1963	1,416.3	1,560.8	0.9	0.9	21,327.7	13.7
1964	1,309.0	1,605.9	0.8	0.9	21,030.8	13.1
1965	1,681.1	1,640.6	1.0	1.0	21,071.3	12.8
1966	1,869.8	1,790.1	1.0	1.1	21,151.0[d]	11.8
1967	2,271.5	1,934.7	1.2		21,487.8[d]	11.1

a/ Excludes lease condensate.

b/ Includes offshore Texas and Louisiana.

c/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 3,778.2 million barrels in 1966 and 3,549.0 million barrels in 1967; increasing the RPR to 13.9 in 1966 and 12.9 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

P.A.D IV

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	265.1	189.0	1.4		2,119.8	11.2
1957	265.9	196.0	1.4	1.5	2,189.7	11.2
1958	363.0	215.5	1.7	1.3	2,337.2	10.8
1959	192.3	241.8	0.8	1.1	2,287.7	9.5
1960	224.0	245.3	0.9	0.9	2,266.4	9.2
1961	257.5	255.0	1.0	0.8	2,269.2	8.9
1962	103.3	240.6	0.4	0.8	2,131.9	8.9
1963	218.0	236.4	0.9	0.7	2,113.5	8.9
1964	142.6	234.1	0.6	0.8	2,022.0	8.6
1965	176.3	231.2	0.8	0.7	1,967.1	8.5
1966	170.8	226.9	0.8	0.8	1,911.0[c]	8.4
1967	212.9	231.5	0.9		1,892.4[c]	8.2

a/ Excludes lease condensate.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

c/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 476.6 million barrels in 1966 and 477.2 million barrels in 1967; increasing the RPR to 10.5 in 1966 and 10.2 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

P. A. D V[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply (1)	Reported Data: Production (2)	Ratio of New Supply to Production: Annual (3)	Ratio of New Supply to Production: Three-Year Moving Average[c] (4)	Total Reserves, End of Year (5)	Reserve-Production Ratio (6)
1956	320.7	350.8	0.9		3,771.4	10.8
1957	327.5	339.1	1.0	1.1	3,759.8	11.1
1958	420.3	313.7	1.3	1.0	3,866.4	12.3
1959	203.3	307.2	0.7	0.9	3,762.5	12.2
1960	200.0	304.0	0.7	0.7	3,658.5	12.0
1961	254.7	298.5	0.9	0.9	3,614.7	12.1
1962	329.3	295.6	1.1	0.9	3,648.4	12.3
1963	251.3	300.0	0.8	1.6	3,599.7	12.0
1964	843.6	309.9	2.7	2.1	4,208.3	13.6
1965	846.0	327.0	2.6	2.3	4,727.3	14.5
1966	560.2	358.1	1.6	1.5	4,929.4[d]	13.8
1967	209.2	388.3	0.5		4,750.2[d]	12.2

a/ Excludes lease condensate.

b/ Excludes Arizona and Nevada which are not given separately, but includes offshore California and Alaska beginning in 1964.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 2,564.0 million barrels in 1966 and 2,795.9 million barrels in 1967; increasing the RPR to 20.9 in 1966 and 19.4 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

LOUISIANA[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	690.1	270.0	2.6		3,675.4	13.6
1957	480.7	298.5	1.6	1.9	3,857.6	12.9
1958	466.1	279.7	1.7	2.1	4,044.0	14.5
1959	934.5	318.4	2.9	2.0	4,660.1	14.6
1960	471.6	346.3	1.4	1.9	4,785.4	13.8
1961	512.1	366.3	1.4	1.4	4,931.2	13.5
1962	573.2	417.8	1.4	1.2	5,086.6	12.2
1963	450.6	448.6	1.0	1.2	5,088.6	11.3
1964	552.3	478.5	1.2	1.1	5,162.4	10.8
1965	596.7	513.3	1.2	1.2	5,245.8	10.2
1966	746.5	583.9	1.3	1.2	5,408.4[d]	9.3
1967	727.4	679.9	1.1		5,455.9[d]	8.0

a/ Excludes lease condensate.

b/ Includes offshore.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 422.3 million barrels in 1966 and 213.3 million barrels in 1967; increasing the RPR to 10.0 in 1966 and 8.3 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

TEXAS[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	927.4	1,077.8	0.9		14,783.1	13.7
1957	829.3	1,057.3	0.8	0.8	14,555.1	13.8
1958	676.5	909.4	0.7	1.0	14,322.2	15.7
1959	1,476.5	939.0	1.6	1.1	14,859.7	15.8
1960	794.9	896.1	0.9	1.2	14,758.5	16.5
1961	989.5	898.4	1.1	0.9	14,849.6	16.5
1962	692.4	893.7	0.8	0.9	14,648.3	16.4
1963	840.1	915.3	0.9	0.8	14,573.1	15.9
1964	655.4	928.7	0.7	0.9	14,299.8	15.4
1965	929.4	926.2	1.0	0.8	14,303.0	15.4
1966	770.7	996.6	0.8	1.1	14,077.1[d]	14.1
1967	1,467.5	1,050.5	1.4		14,494.1[d]	13.8

[a] Excludes lease condensate.

[b] Includes offshore.

[c] Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

[d] Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 2,757.7 million barrels in 1966 and 2,813.5 million barrels in 1967; increasing the RPR to 16.9 in 1966 and 16.5 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

OKLAHOMA

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	205.6	211.8	1.0		2,009.8	9.5
1957	143.2	211.5	0.7	0.8	1,941.5	9.2
1958	155.1	198.5	0.8	0.8	1,898.1	9.6
1959	160.1	193.4	0.8	0.7	1,864.8	9.6
1960	115.4	189.7	0.6	0.8	1,790.5	9.4
1961	184.7	187.8	1.0	0.8	1,787.4	9.5
1962	137.1	196.2	0.7	0.7	1,728.3	8.8
1963	94.4	194.5	0.5	0.7	1,628.2	8.4
1964	156.6	198.9	0.8	0.6	1,585.9	8.0
1965	137.9	206.3	0.7	0.8	1,517.5	7.4
1966	218.3	217.6	1.0	0.8	1,518.2[c]	7.0
1967	163.2	222.5	0.7		1,458.9[c]	6.6

a/ Excludes lease condensate.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

c/ Excluded additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 662.3 million barrels in 1966 and 597.2 million barrels in 1967; increasing the RPR to 10.0 in 1966 and 9.2 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

WYOMING
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Production	Ratio of New Supply to Production: Annual	Ratio of New Supply to Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	95.9	106.3	0.9		1,363.2	12.8
1957	166.1	109.5	1.5	1.1	1,419.7	13.0
1958	102.6	113.6	0.9	1.1	1,408.7	12.4
1959	119.5	125.3	1.0	1.0	1,402.9	11.2
1960	155.2	130.8	1.2	0.9	1,427.4	10.9
1961	96.1	143.0	0.7	0.7	1,380.5	9.7
1962	53.7	137.2	0.4	0.6	1,297.0	9.5
1963	91.3	134.0	0.7	0.6	1,254.3	9.4
1964	90.9	140.7	0.6	0.7	1,204.5	8.6
1965	104.8	140.4	0.7	0.6	1,168.9	8.3
1966	38.6	135.0	0.3	0.6	1,072.5[c]	7.9
1967	109.7	138.7	0.8		1,043.5[c]	7.5

a/ Excludes lease condensate.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

c/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 165.8 million barrels in 1966 and 128.2 million barrels in 1967; increasing the RPR to 9.2 in 1966 and 8.4 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

NEW SUPPLY, PRODUCTION AND TOTAL RESERVES OF CRUDE OIL[a]

CALIFORNIA[b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data		Ratio of New Supply to Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Production	Annual	Three-Year Moving Average[c]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	320.7	350.8	0.9		3,771.4	10.8
1957	327.5	339.1	1.0	1.1	3,759.8	11.1
1958	420.3	313.7	1.3	1.0	3,866.4	12.3
1959	203.3	307.2	0.7	0.9	3,762.5	12.2
1960	200.0	304.0	0.7	0.7	3,658.5	12.0
1961	254.7	298.5	0.9	0.9	3,614.7	12.1
1962	329.3	295.6	1.1	0.9	3,648.4	12.3
1963	251.3	300.0	0.8	1.6	3,599.7	12.0
1964	824.6	298.9	2.8	2.0	4,125.4	13.8
1965	758.0	315.9	2.4	2.1	4,567.5	14.5
1966	384.2	343.8	1.1	1.2	4.607.9[d]	13.4
1967	120.9	359.4	0.3		4,369.4[d]	12.2

a/ Excludes lease condensate.

b/ Includes offshore.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

d/ Excludes additional known reserves (in excess of proved reserves) considered economically available by application of fluid injection, amounting to 2,432.0 million barrels in 1966 and 2,572.4 million barrels in 1967; increasing the RPR to 20.5 in 1966 and 19.3 in 1967.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

APPENDIX 6

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES OF NATURAL GAS LIQUIDS BY PAD DISTRICTS AND MAJOR PRODUCING STATES

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

P. A. D. I[b]
1956-1967
(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	1.3	4.9	0.3		29.9	6.1
1957	1.5	5.0	0.3	3.3	26.4	5.3
1958	45.3	4.7	9.6	1.6	67.0	14.3
1959	(26.0)	3.2	--	2.7	37.8	11.8
1960	12.9	3.9	3.3	0.6	46.8	12.0
1961	21.3	7.8	2.7	2.2	60.3	7.7
1962	7.5	7.4	1.0	2.0	60.4	8.2
1963	18.0	8.2	2.2	1.5	70.2	8.6
1964	8.4	7.5	1.1	1.7	71.1	9.5
1965	13.0	7.8	1.7	1.5	76.3	9.8
1966	13.0	7.3	1.8	1.5	82.0	11.2
1967	7.5	6.7	1.1		82.8	12.4

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Excludes Florida which is not shown separately.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

P. A. D. II[b]
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	38.2	41.3	0.9		560.6	13.6
1957	49.1	46.4	1.1	1.5	582.3	12.5
1958	105.1	41.7	2.5	2.2	645.7	15.5
1959	127.2	42.0	3.0	1.9	730.9	17.4
1960	7.1	43.1	0.2	1.1	694.9	16.1
1961	10.5	41.2	0.3	0.5	664.2	16.1
1962	43.1	37.5	1.1	0.6	669.8	17.9
1963	13.7	41.1	0.3	1.2	642.4	15.6
1964	91.7	47.2	1.9	1.2	686.9	14.6
1965	56.8	51.2	1.1	2.3	692.5	13.5
1966	235.9	65.9	3.6	1.9	862.5	13.1
1967	57.9	68.0	0.9		852.4	12.5

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ 1956 excludes North Dakota which was not given separately.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

P. A. D. III[b]
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	744.2	263.4	2.8		4,907.4	18.6
1957	62.8	267.3	0.2	1.8	4,702.9	17.6
1958	654.4	262.8	2.5	1.5	5,094.5	19.4
1959	490.8	301.1	1.6	2.0	5,284.2	17.5
1960	636.6	343.2	1.9	1.7	5,577.6	16.3
1961	601.4	371.3	1.6	1.7	5,807.7	15.6
1962	678.9	386.4	1.8	1.8	6,100.2	15.8
1963	820.9	427.8	1.9	1.6	6,493.3	15.2
1964	479.6	443.1	1.1	1.5	6,529.8	14.7
1965	742.2	459.0	1.6	1.4	6,813.0	14.8
1966	643.9	479.9	1.3	1.5	6,977.0	14.5
1967	854.6	533.7	1.6		7,297.8	13.7

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Excludes Alabama which is not given separately, but includes offshore Texas and Louisiana.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports of the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

P.A.D. IV
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

	Reported Data		Ratio of New Supply to Net Production			
Year	New Supply	Net Production	Annual	Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	8.8	5.0	1.8		73.7	14.7
1957	0.4	4.1	0.1	2.8	70.0	17.1
1958	28.7	4.2	6.8	4.9	94.5	22.5
1959	59.3	9.7	6.1	5.2	144.1	14.9
1960	51.5	12.8	4.0	3.4	182.8	14.3
1961	13.7	13.8	1.0	1.9	182.7	13.2
1962	11.7	12.9	0.9	0.9	181.5	14.1
1963	9.7	13.2	0.7	1.1	178.0	13.5
1964	20.8	12.9	1.6	0.9	185.9	14.4
1965	6.0	13.0	0.5	0.7	178.9	13.8
1966	(1.3)	12.2		0.4	165.4	13.6
1967	10.3	13.0	0.8		162.7	12.5

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports of the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

P. A. D. V[b]
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	17.2	30.4	0.6		311.7	10.3
1957	23.7	29.7	0.8	0.7	305.7	10.3
1958	24.8	28.2	0.9	1.2	302.3	10.7
1959	52.1	29.1	1.8	1.1	325.3	11.2
1960	17.0	28.4	0.6	1.4	313.9	11.1
1961	47.8	27.5	1.7	0.7	334.2	12.2
1962	(8.6)	25.9		0.7	299.7	11.6
1963	15.9	25.5	0.6	0.2	290.1	11.4
1964	8.2	25.3	0.3	0.5	273.0	10.8
1965	14.3	24.5	0.6	0.3	262.8	10.7
1966	2.8	23.4	0.1	0.2	242.2	10.4
1967	(0.5)	23.1			218.6	9.5

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Data includes California only and includes offshore.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

LOUISIANA[b]
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[c]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	122.2	43.2	2.8		1,014.9	23.5
1957	51.4	47.1	1.1	2.8	1,019.2	21.6
1958	227.2	50.4	4.5	3.0	1,196.0	23.7
1959	235.3	73.5	3.2	3.0	1,357.8	18.5
1960	157.5	82.3	1.9	2.2	1,433.0	17.4
1961	156.4	95.6	1.6	2.2	1,493.8	15.6
1962	308.6	104.6	3.0	2.3	1,697.8	16.2
1963	265.9	122.9	2.2	2.3	1,840.8	15.0
1964	230.7	130.0	1.8	2.2	1,941.5	14.9
1965	371.1	143.8	2.6	2.0	2,168.8	15.1
1966	270.5	156.9	1.7	2.4	2,282.4	14.5
1967	510.0	185.2	2.8		2,607.2	14.1

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Includes offshore.

c/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVE OF NATURAL GAS LIQUIDS [a]

TEXAS [b]

1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data		Ratio of New Supply to Net Production		Total Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[c]		
	(1)	(2)	(3)	(4)	(5)	(6)
1956	533.4	198.9	2.7		3,379.9	17.0
1957	90.7	199.0	0.5	1.6	3,271.6	16.4
1958	309.8	189.4	1.6	1.1	3,392.0	17.9
1959	241.7	203.3	1.2	1.5	3,430.4	16.9
1960	393.9	228.1	1.7	1.5	3,596.2	15.8
1961	399.4	240.1	1.7	1.6	3,755.5	15.6
1962	320.8	246.9	1.3	1.6	3,829.4	15.5
1963	480.5	267.5	1.8	1.3	4,042.4	15.1
1964	190.9	273.5	0.7	1.3	3,959.8	14.5
1965	378.7	278.9	1.4	1.1	4,059.6	14.6
1966	324.3	282.3	1.1	1.2	4,101.6	14.5
1967	300.1	298.7	1.0		4,103.0	13.7

[a] Includes lease condensate, natural gasoline and liquefied gases.

[b] Includes offshore.

[c] Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS [a]

OKLAHOMA
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

	Reported Data		Ratio of New Supply to Net Production			
Year	New Supply	Net Production	Annual	Three-Year Moving Average [b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	32.1	30.9	1.0		355.6	11.5
1957	21.1	34.1	0.6	1.0	342.6	10.0
1958	44.5	29.6	1.5	1.1	357.5	12.1
1959	38.4	28.3	1.4	1.0	367.6	13.0
1960	(0.8)	28.5		0.7	338.3	11.9
1961	17.7	26.8	0.7	0.7	329.2	12.3
1962	40.2	22.4	1.8	0.9	347.0	15.5
1963	7.0	25.8	0.3	1.2	328.2	12.7
1964	43.7	29.0	1.5	1.1	342.9	11.8
1965	47.4	32.0	1.5	2.4	358.3	11.2
1966	160.1	42.8	3.7	2.0	475.6	11.1
1967	21.5	41.3	0.5		455.8	11.0

[a] Includes lease condensate, natural gasoline and liquefied gases.

[b] Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES
OF NATURAL GAS LIQUIDS[a]

WYOMING
1956-1967

(Volumes in Millions of Barrels of 42 U.S. Gallons)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1956	7.4	3.9	1.9		53.9	13.8
1957	0.2	2.9	0.1	1.1	51.2	17.7
1958	2.7	3.0	0.9	2.8	50.9	17.0
1959	27.3	4.9	5.6	4.2	73.3	15.0
1960	29.3	6.2	4.7	3.8	96.4	15.5
1961	10.6	6.6	1.6	2.4	100.4	15.2
1962	7.4	7.0	1.1	1.2	100.8	14.4
1963	5.3	6.6	0.8	0.6	99.5	15.1
1964		7.0		0.7	92.5	13.2
1965	9.1	7.7	1.2	0.4	93.9	12.2
1966	(0.3)	7.3		0.8	86.3	11.8
1967	8.7	7.8	1.1		87.2	10.0

a/ Includes lease condensate, natural gasoline and liquefied gases.

b/ Based on three-year moving average of the data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

EXHIBITS

ENERGY CONSUMPTION IN THE UNITED STATES BY ENERGY SOURCE

Actual 1947 - 1967, Projections - 1975, 1985, Extrapolation - 2000

Year	Consumption in Quadrillion Btu: Total	Petroleum a/	Natural Gas (Dry)	All Other Energy Sources: Coal b/	Nuclear Power	Hydropower	Energy Sources as a Percent of Total Consumption: Total	Petroleum a/	Natural Gas (Dry)	All Other Energy Sources: Coal b/	Nuclear Power	Hydropower
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Actual												
1947	33.2	11.4	4.5	15.8		1.5	100.0	34.3	13.6	47.6		4.5
1948	34.0	12.6	5.0	14.9		1.5	100.0	37.1	14.7	43.8		4.4
1949	31.6	12.1	5.3	12.6		1.6	100.0	38.3	16.8	39.9		5.0
1950	34.2	13.5	6.2	12.9		1.6	100.0	39.5	18.1	37.7		4.7
1951	36.9	14.9	7.2	13.2		1.6	100.0	40.4	19.5	35.8		4.3
1952	36.6	15.3	7.8	11.9		1.6	100.0	41.8	21.3	32.5		4.4
1953	37.7	16.1	8.2	11.9		1.5	100.0	42.7	21.7	31.6		4.0
1954	36.4	16.1	8.6	10.2		1.5	100.0	44.3	23.6	28.0		4.1
1955	39.9	17.5	9.2	11.7		1.5	100.0	43.9	23.0	29.3		3.8
1956	42.0	18.6	9.8	12.0		1.6	100.0	44.3	23.3	28.6		3.8
1957	41.9	18.6	10.4	11.3	n/	1.6	100.0	44.4	24.8	27.0	n/	3.8
1958c/	42.0	19.2	11.0	10.1	n/	1.7	100.0	45.7	26.2	24.1	n/	4.0
1959	43.5	19.7	12.0	10.1	n/	1.7	100.0	45.3	27.6	23.2	n/	3.9
1960	45.0	20.1	12.7	10.4	n/	1.8	100.0	44.7	28.2	23.1	n/	4.0
1961	45.5	20.5	13.2	10.2	n/	1.6	100.0	45.1	29.0	22.4	n/	3.5
1962	47.7	21.3	14.1	10.5	n/	1.8	100.0	44.6	29.6	22.0	n/	3.8
1963	49.6	22.0	14.8	11.1	n/	1.7	100.0	44.3	29.8	22.4	0.1	3.4
1964	51.6	22.4	15.6	11.7	n/	1.9	100.0	43.4	30.2	22.6	0.1	3.7
1965	53.8	23.2	16.1	12.4	n/	2.1	100.0	43.1	29.9	23.0	0.1	3.9
1966	56.8	24.4	17.3	13.0	0.1	2.1	100.0	42.9	30.4	22.9	0.1	3.7
1967	58.8	25.2	18.4	12.9	0.1	2.3	100.0	42.8	31.3	21.9	0.1	3.9
Projections												
1975	79.5	32.0	25.5		22.0		100.0	40.2	32.1		27.7	
1985	113.5	42.0	34.5		37.0		100.0	37.0	30.4		32.6	
Extrapolation												
2000	172.0	56.0	42.0		74.0		100.0	32.6	24.4		43.0	

a/ Petroleum products, including still gas, liquefied refinery gas, and natural gas liquids.

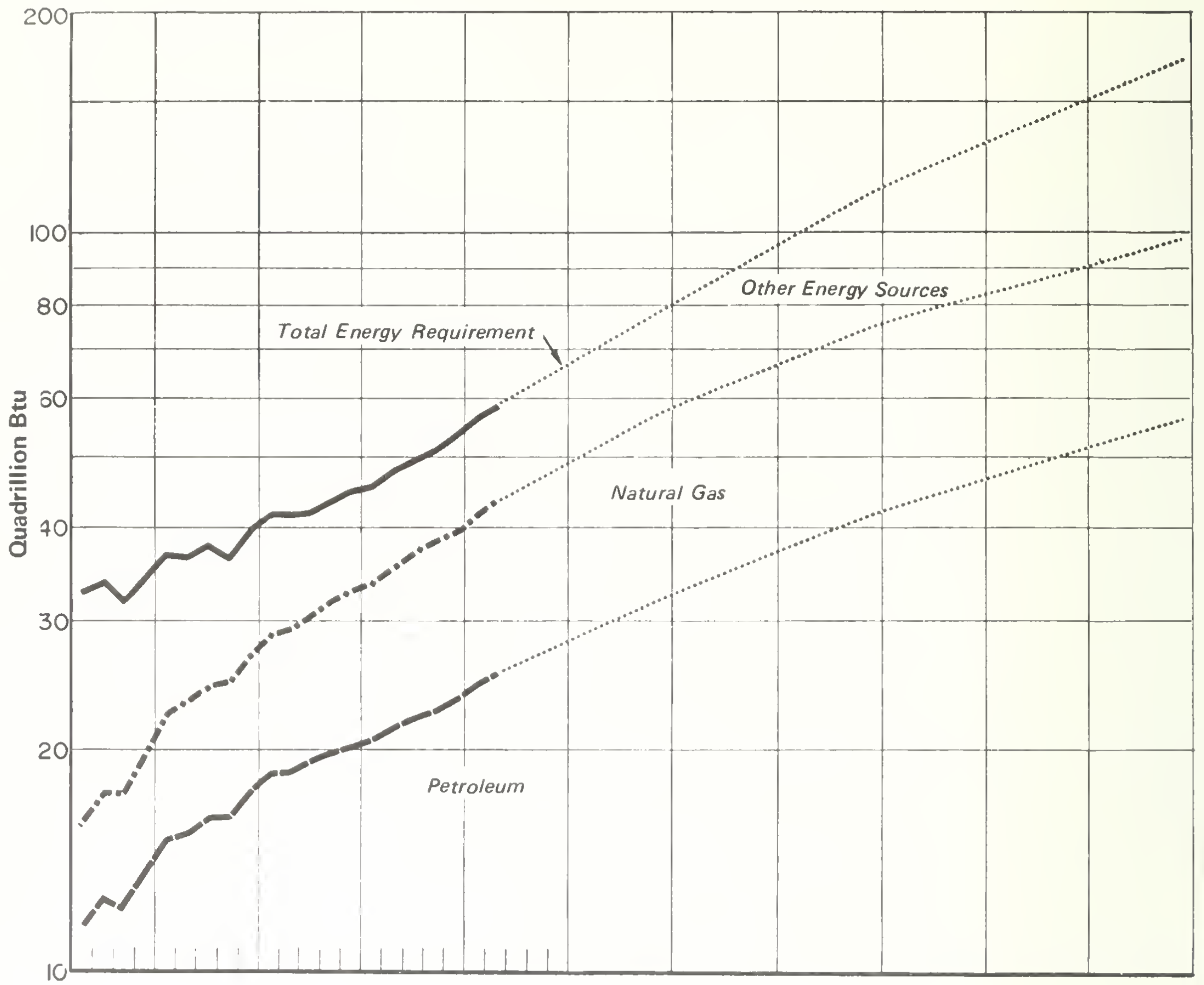
b/ Includes bituminous, anthracite and lignite.

c/ 1947-1958 on a 48-state basis; 1959-1967 on a 50-state basis.

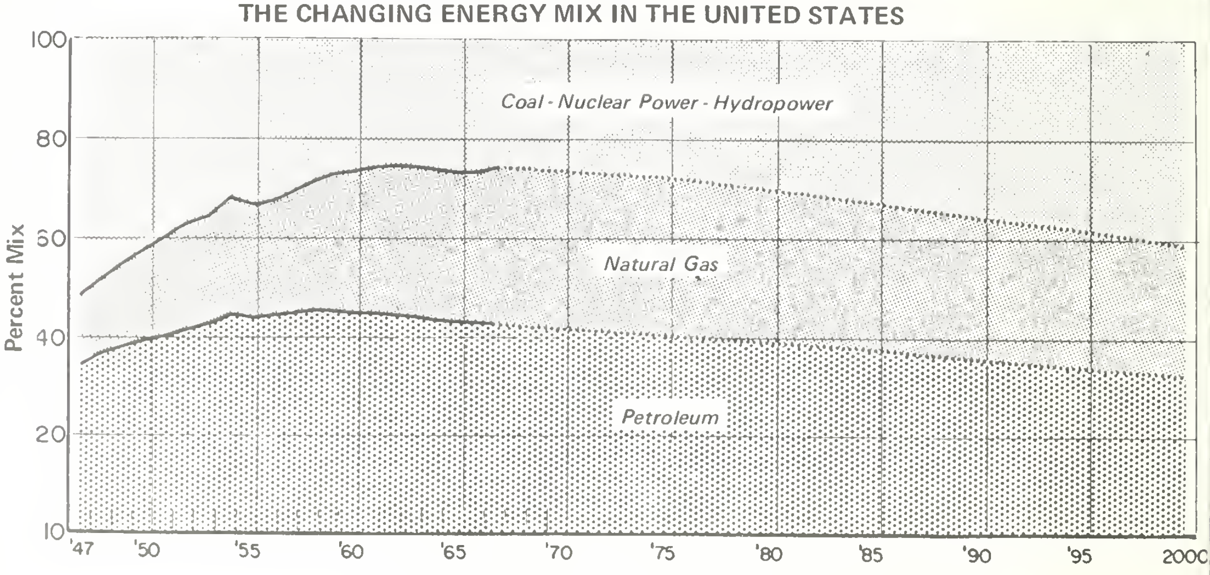
n/ Less than 50 trillion Btu and/or 0.1 percent of total.

Source: Actual years - Bureau of Mines, U. S. Department of the Interior; projections - Foster Associates, Inc.

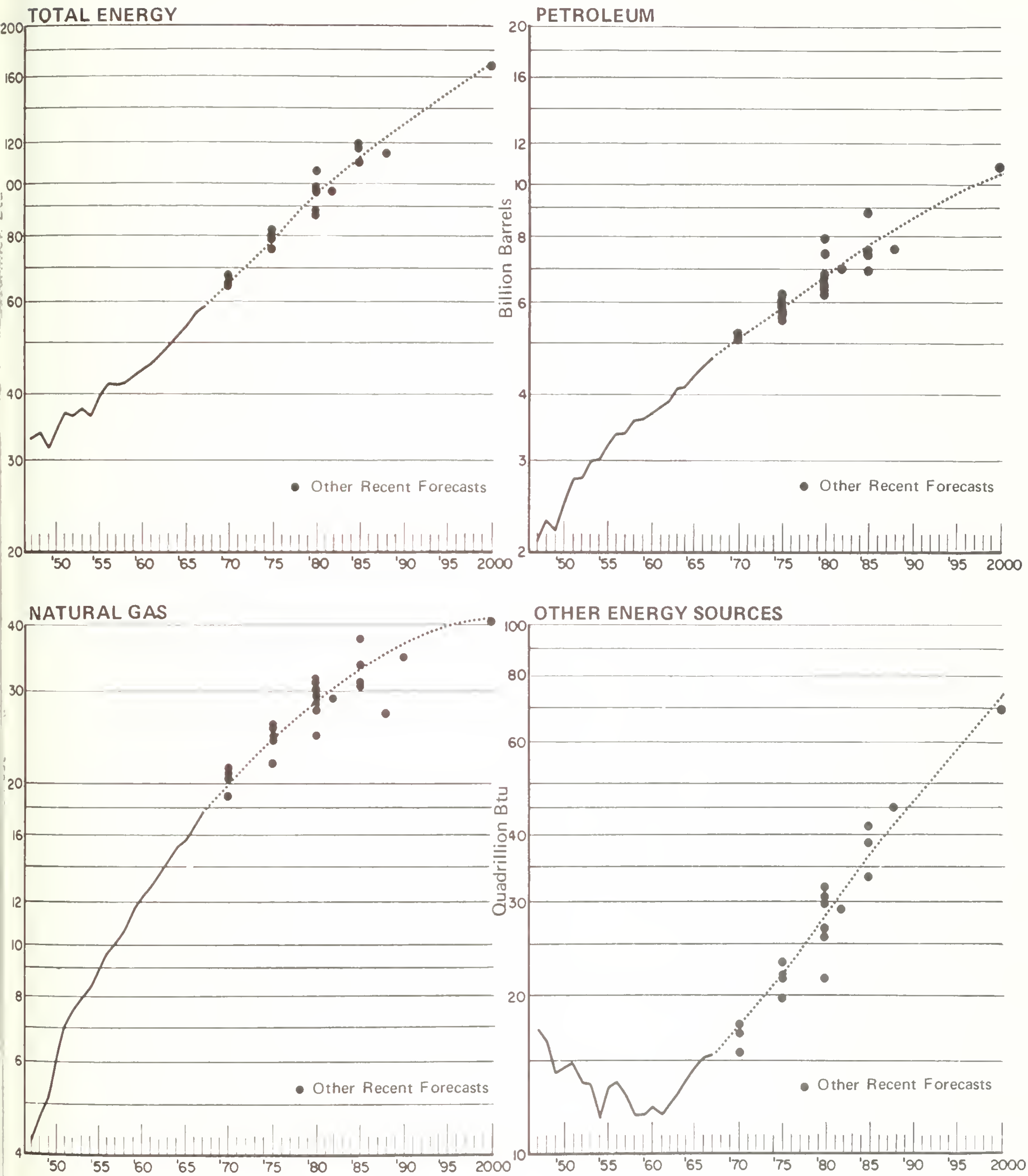
ENERGY CONSUMPTION IN THE UNITED STATES
BY ENERGY SOURCE



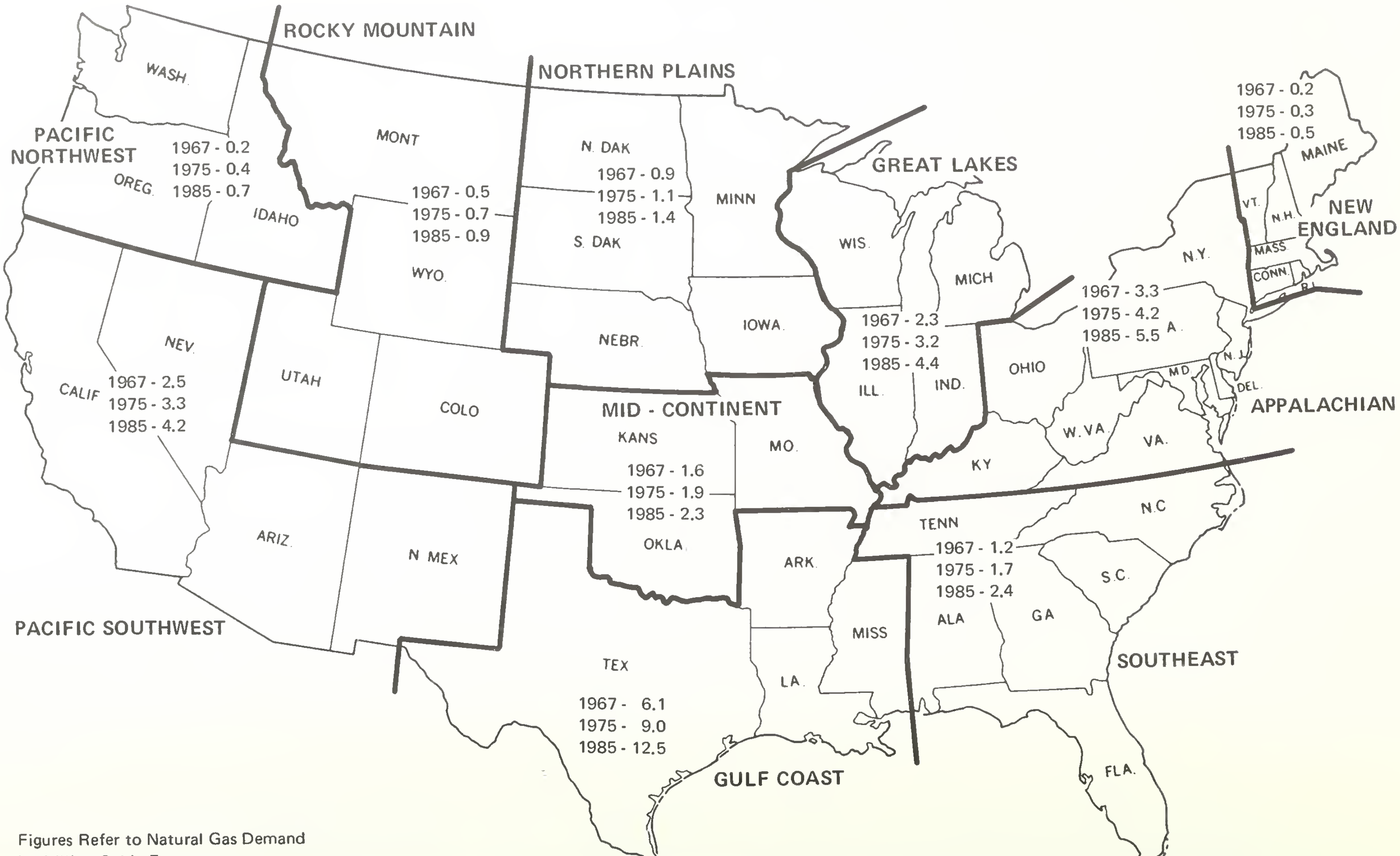
THE CHANGING ENERGY MIX IN THE UNITED STATES



ENERGY CONSUMPTION IN THE UNITED STATES BY ENERGY SOURCE

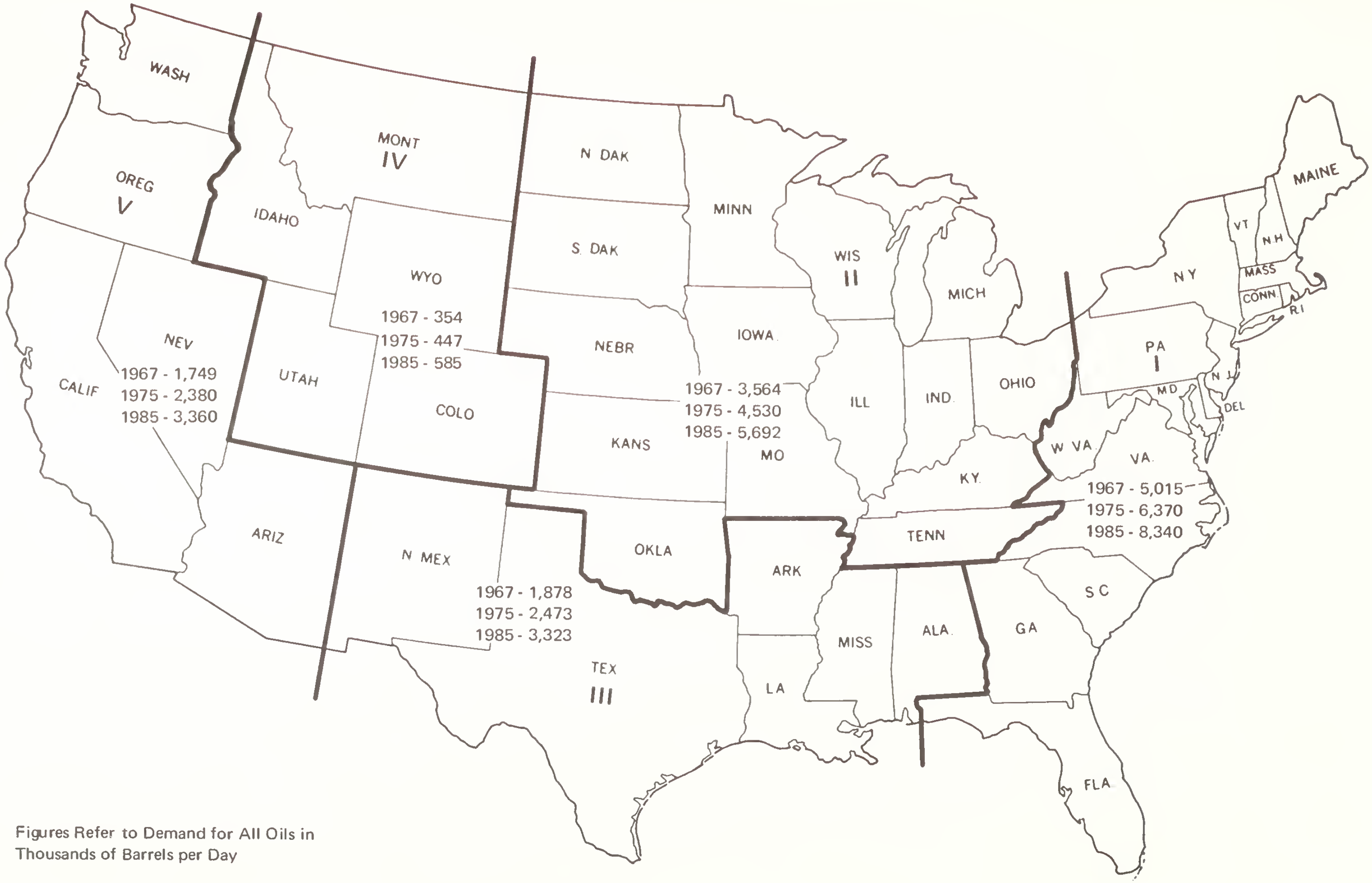


NATURAL GAS DEMAND BY REGIONS



Figures Refer to Natural Gas Demand in Trillion Cubic Feet

PETROLEUM DEMAND
IN
PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS



Figures Refer to Demand for All Oils in
Thousands of Barrels per Day

NEW SUPPLY, NET PRODUCTION AND TOTAL RESERVES OF NATURAL GAS IN THE UNITED STATES[a/]
1947-1967
(Volumes in Billions of Cubic Feet at 14.73 psia)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b/]	Total Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1947	10,921	5,599	1.95		165,026	29.5
1948	13,823	5,975	2.31	2.10	172,925	28.9
1949	12,606	6,211	2.03	2.02	179,402	28.9
1950	11,985	6,855	1.75	1.93	184,585	26.9
1951	15,966	7,924	2.01	1.81	192,759	24.3
1952	14,268	8,593	1.66	1.97	198,632	23.1
1953	20,342	9,188	2.21	1.63	210,299	22.9
1954	9,547	9,375	1.02	1.81	210,561	22.5
1955	21,898	10,063	2.18	1.85	222,483	22.1
1956	24,716	10,849	2.28	2.06	236,483	21.8
1957	20,008	11,440	1.75	1.89	245,230	21.4
1958	18,897	11,423	1.65	1.69	252,762	22.1
1959	20,621	12,373	1.67	1.45	261,113	21.1
1960	13,844	13,019	1.06	1.31	262,219	20.1
1961	16,350	13,377	1.22	1.22	265,352	19.8
1962	18,768	13,634	1.38	1.28	270,645	19.9
1963	18,104	14,541	1.25	1.31	274,461	18.9
1964	20,105	15,341	1.31	1.29	279,420	18.2
1965	21,158	16,245	1.30	1.23	284,484	17.5
1966	19,246	17,478	1.10	1.18	286,386	16.4
1967	21,093	18,358	1.15		289,272	15.8

a/ Excludes Alaska where reported separate.

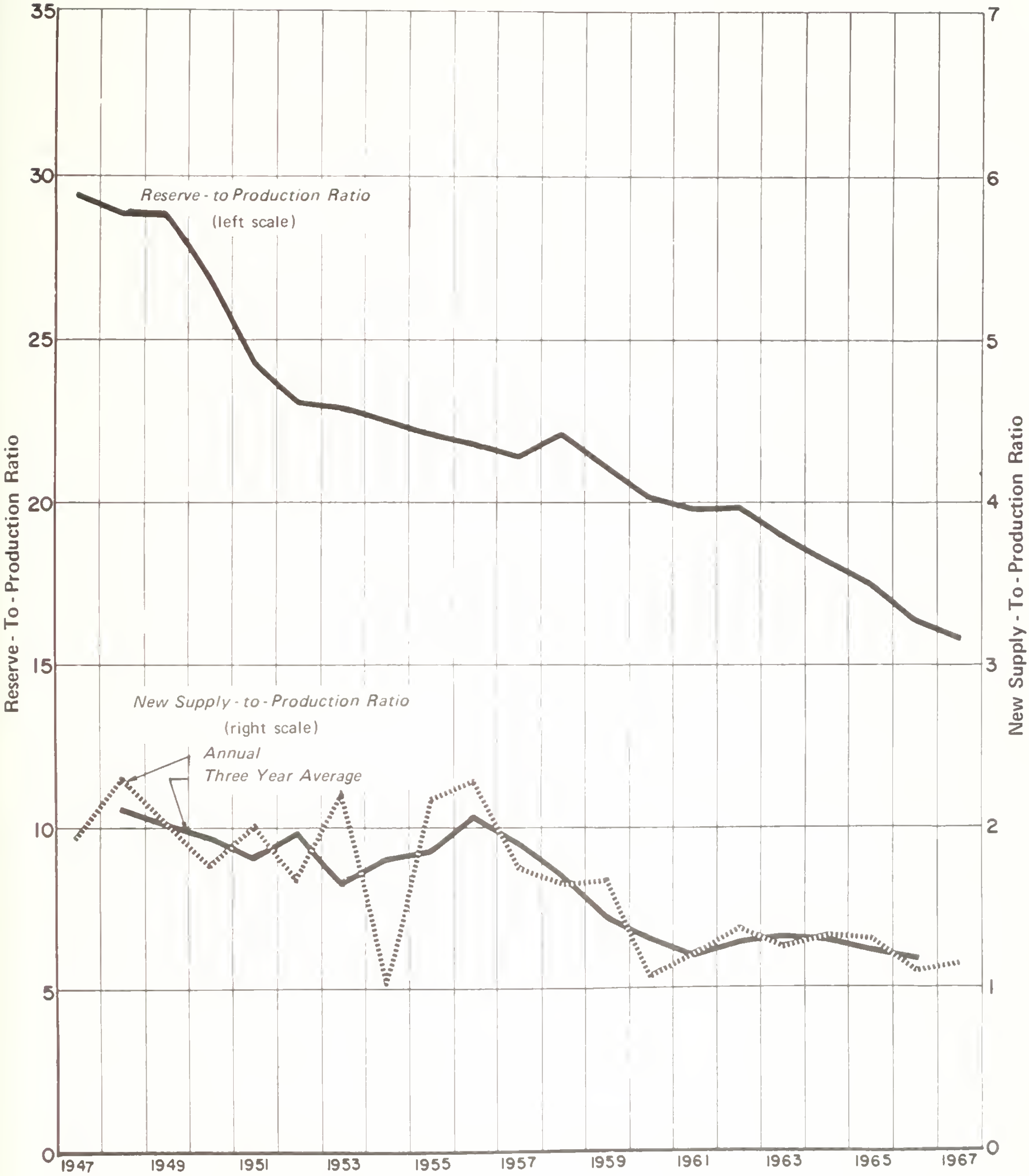
b/ Based on three-year moving average of the data in cols. (1) and (2), centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

TREND IN RESERVE–TO–PRODUCTION RATIO AND NEW SUPPLY–TO–PRODUCTION RATIO FOR NATURAL GAS

UNITED STATES[a)]

1947-1967

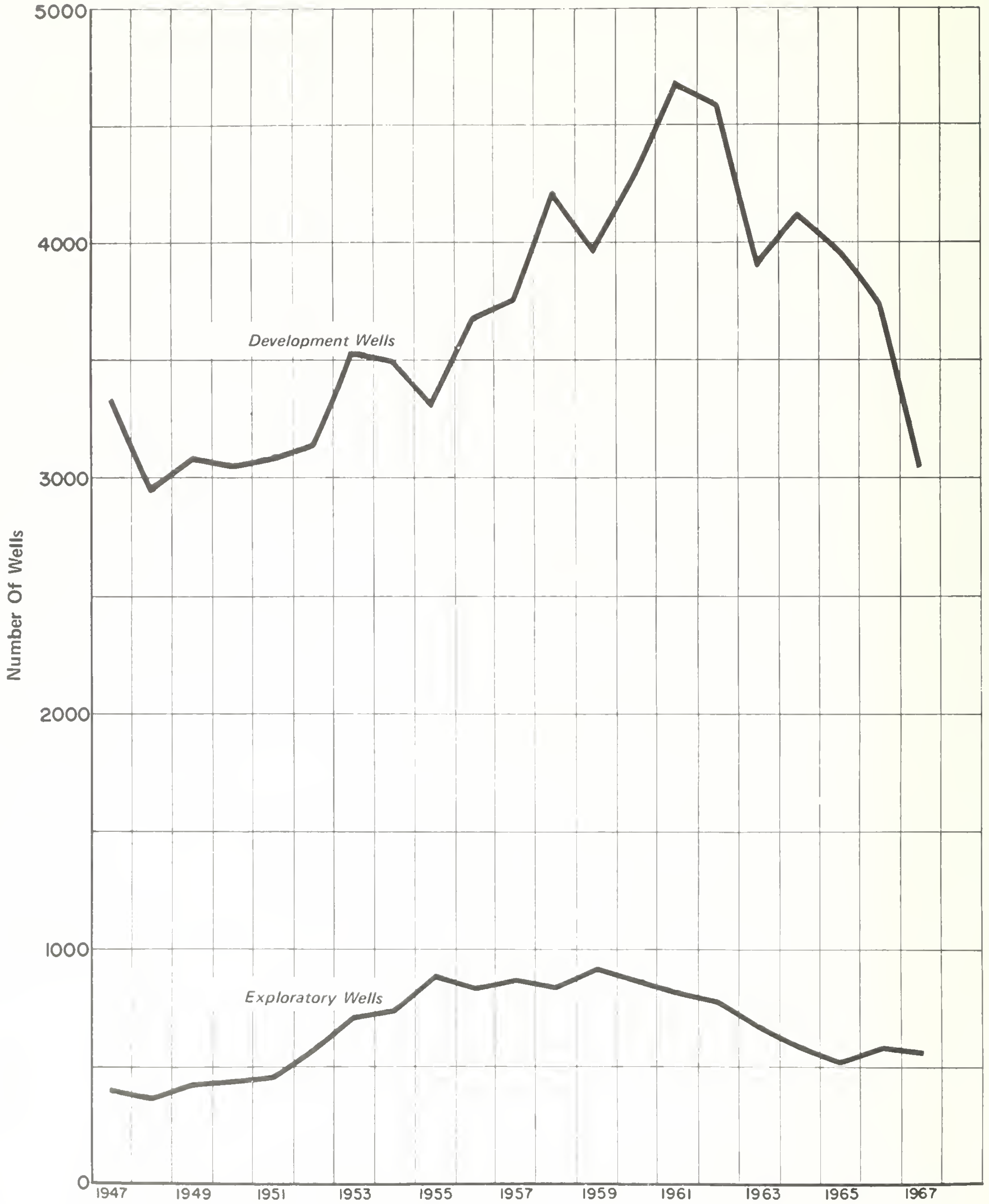


a) Excludes Alaska where listed separately

TREND IN GAS WELL DRILLING

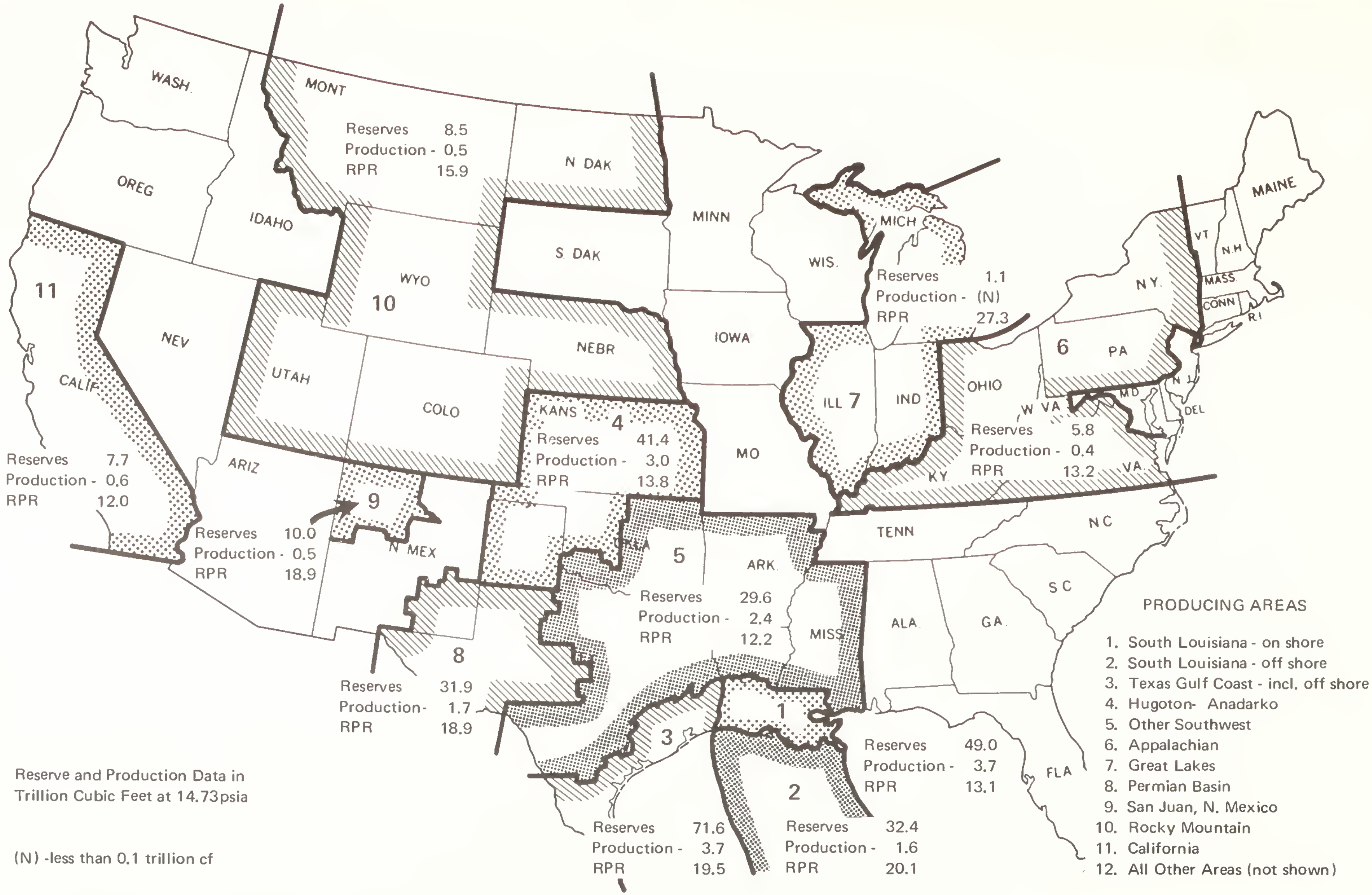
UNITED STATES[a]

1947-1967



a) Excludes Alaska where listed separately

NATURAL GAS PRODUCING AREAS 1967



PRODUCTION OF NATURAL GAS IN IMPORTANT PRODUCING AREAS
1967 Compared with 1956
(Billion Cubic Feet at 14.73 Psia)

Producing Area[a]	Volume 1956 (1)	Volume 1967 (2)	Percent of U.S. Production 1956 (3)	Percent of U.S. Production 1967 (4)
South Louisiana				
Offshore	122	1,624	1.1	8.9
Onshore	1,271	3,747	11.7	20.4
Texas Gulf Coast[b]	2,550	3,679	23.5	20.0
Hugoton-Anadarko	1,881	3,002	17.3	16.4
Other Southwest	2,210	2,426	20.4	13.2
Permian Basin	1,364	1,689	12.6	9.2
San Juan Basin, New Mexico	197	532	1.8	2.9
Rocky Mountain	313	432	2.9	2.9
California	485	641	4.5	3.5
All Others	456	486	4.2	2.6
Total U.S., Excluding Alaska	10,849	18,358	100.0	100.0

a/ For identification of producing area see page 121. (Division between South Louisiana offshore and onshore is estimated at the Chapman Line.)

b/ Includes offshore production estimated at 173 billion cubic feet in 1967.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NATURAL GAS RESERVES IN IMPORTANT PRODUCING AREAS
1967 Compared with 1956
(Billion Cubic Feet at 14.73 Psia)

Producing Area[b]	Total Reserves Year-End 1956 (1)	Total Reserves Year-End 1967 (2)	Percent of Total Reserves 1956 (3)	Percent of Total Reserves 1967 (4)	Reserve Production Ratio 1956 (5)	Reserve Production Ratio 1967 (6)
South Louisiana						
Offshore	5,977	32,438	2.5	11.2	49.0	20.0
Onshore	33,356	48,985	14.1	16.9	26.2	13.1
Texas Gulf Coast[b]	62,616	71,592	26.5	24.8	24.6	19.5
Hugoton-Anadarko	46,386	41,396	19.6	14.3	24.7	13.8
Other Southwest	27,189	29,582	11.5	10.2	12.3	12.2
Permian Basin	23,632	31,869	10.0	11.0	17.3	18.9
San Juan Basin, New Mexico	15,842	10,031	6.7	3.5	80.4	18.9
Rocky Mountain	7,556	8,465	3.2	2.9	24.1	15.9
California	8,704	7,724	3.7	2.7	17.9	12.0
All Others	5,225	7,190	2.2	2.5	11.5	14.8
Total U.S., Excluding Alaska	236,483	289,272	100.0	100.0	21.8	15.8

a/ For identification of producing areas see page 121. (Division between South Louisiana offshore and onshore is estimated at the Chapman Line.)

b/ Includes offshore reserves estimated at 1,745 billion feet at year-end 1967.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NATURAL GAS WELL DRILLING ACTIVITY IN IMPORTANT PRODUCING AREAS 1957 COMPARED WITH 1967[a]

Producing Area[b]	Exploratory Wells 1957 (1)	Exploratory Wells 1967 (2)	Total Wells 1957 (3)	Total Wells 1967* (4)
South Louisiana				
Offshore)	157	34	88	128
Onshore)		47	290	164
Texas Gulf Coast[c]	183	120	667	468
Hugoton-Anadarko[d]	161	118	982	678
Other Southwest[e]	112	68	438	454
Permian Basin				
Texas RR Dists. 7C & 8	32	26	75	170
E. New Mexico	29	10	48	26
San Juan, New Mexico		1	576	231
Rocky Mountain	57	32	168	118
California	16	18	54	73
All Other	118	79	1,234	1,105
Total U. S. (Excluding Alaska)	865	553	4,620	3,615

a/ Includes natural gas and condensate wells.

b/ For identification of producing area see page 121.

c/ Includes offshore.

d/ Includes all of Oklahoma.

e/ Excludes the "Other Southwest" portion of Oklahoma.

* 1967 figures are preliminary.

Sources: Exploratory Wells - American Association of Petroleum Geologists.
Total Wells - The Oil and Gas Journal.

PRODUCTION, NEW SUPPLIES AND TOTAL RESERVES OF NATURAL GAS IN THE GULF OF MEXICO
1947 - 1967

(Billion Cubic Feet at 14.73 Psia)

Year	Production			New Supply			Reserves			Reserve-Production Ratio
	La.	Tex.	Total	La.	Tex.	Total	La.	Tex.	Total	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1947							15		15	
1948				222		222	237		237	
1949				1,137		1,137	1,374		1,374	
1950	1		1	78		78	1,451		1,451	
1951	11		11	440		440	1,880		1,880	
1952	37		37	531		531	2,374		2,374	
1953	42		42	188		188	2,520		2,520	
1954	68		68	207	220	427	2,659	220	2,879	
1955	104		104	2,089	35	2,124	4,644	255	4,899	47.1
1956	122		122	1,455		1,455	5,977	255	6,232	51.1
1957	138	2	140	2,145		2,145	7,984	253	8,237	58.8
1958	203	15	218	1,383		1,383	9,164	238	9,402	43.1
1959	309	13	322	2,362		2,362	11,217	225	11,442	35.5
1960	381	17	398	3,355		3,355	14,191	208	14,399	36.2
1961	455	17	472	1,810	60	1,870	15,546	251	15,797	33.5
1962	559	19	578	4,567		4,567	19,554	232	19,786	34.2
1963	682	20	702	3,623	220	3,843	22,495	432	22,927	32.7
1964	762	21	783	3,676		3,676	25,409	411	25,820	33.0
1965	964	24	988	3,087	92	3,179	27,532	479	28,011	28.4
1966	1,252	61	1,313	2,972	671	3,643	29,252	1,089	30,341	23.1
1967	1,624	173	1,797	4,810	829	5,639	32,438	1,745	34,183	19.0

Source: Estimated by analysis of data reported by AGA Natural Gas Reserves Committee, the Louisiana State Department of Conservation and the Texas Railroad Commission. The statistical techniques used in making these estimates are described in Section II of the present Report.

NOTE: AGA definition of the Gulf of Mexico used, i.e., in Louisiana seaward of the Chapman Line and in Texas seaward of the Coast Line.

ESTIMATES OF POTENTIAL NATURAL GAS RESERVES IN THE UNITED STATES

(Trillion Cubic Feet)

	Hendricks[1]	Imputed From Hendricks and Schweinfurth[2]	Potential Gas Committee[3]
	(1)	(2)	(3)
1. Reserves base (in-place)	4,000	5,000	[4]
2. Economically recoverable	2,000	2,500	1,290
3. Less: Cumulative production to 12/66	314	314	314
4. Remaining economically recoverable	1,686	2,186	976
a. Proved at 12/66	286	286	286
b. Potentially remaining to be discovered	1,400	1,900	690

ESTIMATES OF POTENTIAL NATURAL GAS RESERVES IN THE OUTER CONTINENTAL SHELF[5]

(Trillion Cubic Feet)

	Economically Recoverable Reserves	Cumulative Production to 12/66	Proved Reserves at 12/66	Economically Recoverable Reserves Potentially Remaining To Be Discovered
	(1)	(2)	(3)	(4)
Gulf of Mexico	300	8	34	258
Pacific	38	0	0	38
Alaska	271	0	0	271
Atlantic	211	0	0	211
	820	8	34	778

Footnotes: See following page.

1/ Hendricks, T.A., *Reserves of Oil, Gas and Natural Gas Liquids in the U.S. and the World*, U.S. Geological Survey Circular 522, 1965.
Of the 4,000 trillion cubic feet estimated in place as of 12/65, 2,500 trillion was estimated "to be found by exploration" of which 80 percent, or 2,000 was estimated to be "economically recoverable". These reserves include estimates out to 120 feet of water depth in the Gulf of Mexico and California OCS, according to *United States Petroleum Through* 1980, U.S. Department of the Interior, 1968, at p. 10.

2/ Imputed from data published in *United States Petroleum Through 1980* at p. 11, which data was attributed to an unpublished memorandum dated 9/14/66 by Hendricks, T.A., and Schweinfurth, S.P. These estimates include reserves out to 600 feetwater depth in the Alaska as well as the Gulf of Mexico and the Pacific OCS.

3/ *Potential Supply of Natural Gas in the United States as of December 31, 1966*, Potential Gas Committee, Golden, Colorado. Estimates include OCS reserves out to 600 feet of water depth. However, the estimates exclude Alaska, onshore and OCS.

4/ Not published.

5/ *Potential Mineral Resources of the United States Outer Continental Shelves*, McKelvey, V.E., and others, U.S. Geological Survey, 1968, in press.

The estimates are one of several estimates included in the publication. They are based on data to 1/1/66 out to 200 meter isobaths.

NEW FIELD AND NEW RESERVOIR DISCOVERIES IN
RELATION TO TOTAL ADDITION TO NATURAL GAS RESERVES

Year	New Supplies Added to Reserves[a/]			Percent of Total New Additions	
	Extensions and Revisions	New Field and New Reservoir Discoveries	Total	Extensions and Revisions	New Field and New Reservoir Discoveries
	(1)	(2)	(3)	(4)	(5)
	(Trillion Cubic Feet at 14.73 Psia)				
1956	19.1	5.6	24.7	77.3	22.7
1957	11.1	8.9	20.0	55.5	44.5
1958	13.3	5.6	18.9	70.4	29.6
1959	14.8	5.8	20.6	71.8	28.2
1960	7.2	6.6	13.8	52.2	47.8
1961	9.5	6.9	16.4	57.9	42.1
1962	12.6	6.2	18.8	67.0	33.0
1963	12.5	5.6	18.1	69.1	30.9
1964	13.2	6.9	20.1	65.7	34.3
1965	14.7	6.5	21.2	69.3	30.7
1966	13.2	6.0	19.2	68.8	31.2
1967	15.7	5.4	21.1	74.4	25.6

[a/] Excludes Alaska where shown separately.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

ESTIMATED SOURCES OF NATURAL GAS
TO MEET PROJECTED REQUIREMENTS

(Trillion Cubic Feet Per Year at 14.73 psia)

Year	Requirements	Domestic Net Production[a/]		Overland Net Imports	LNG by Tanker and/or Synthetic Gas from Coal
		Onshore	Outer Continental Shelf		
	(1)	(2)	(3)	(4)	(5)
1967 (Actual)	18.9	16.6	1.8	0.5	
1975	25.8	19.6	5.0	1.2	b/
1985	34.8	19.2	11.6	2.0	2.0

a/ Excludes Alaska.

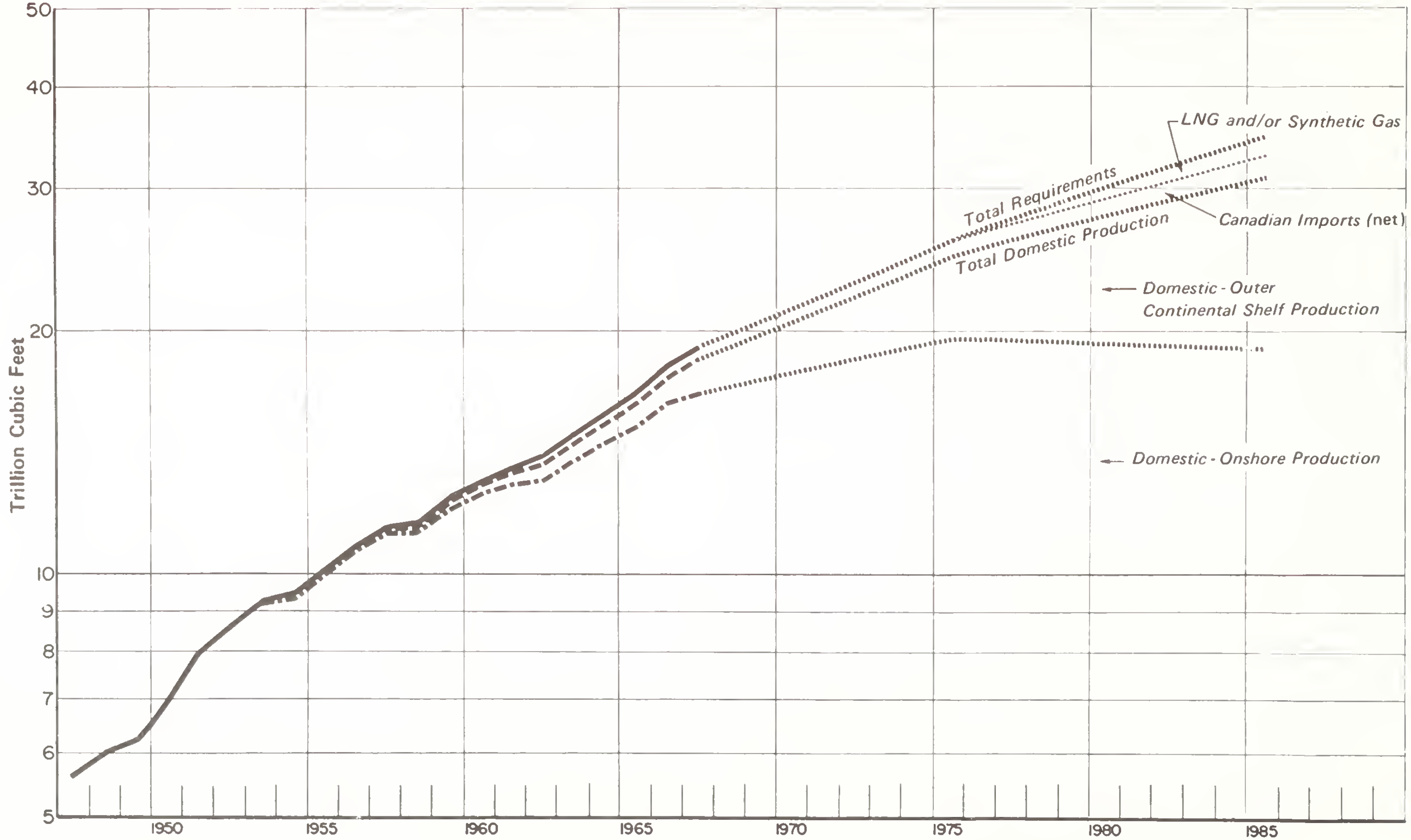
b/ Volumes are projected to be de minimus.

ESTIMATED NEW SUPPLIES OF INDIGENOUS NATURAL
GAS[a/] PROJECTED TO MEET REQUIREMENTS AND MAINTAIN
A MINIMUM RESERVE INVENTORY OF 12 YEARS

Year	Onshore	Outer Continental Shelf	Total
	(1)	(2)	(3)
1967 (Actual)	15.5	5.6	21.1
1975	16.9	8.1	25.0
1985	18.0	19.6	37.6
Cumulative			
1968-1975	133.7	52.3	186.0
1976-1985	184.8	164.8	349.6

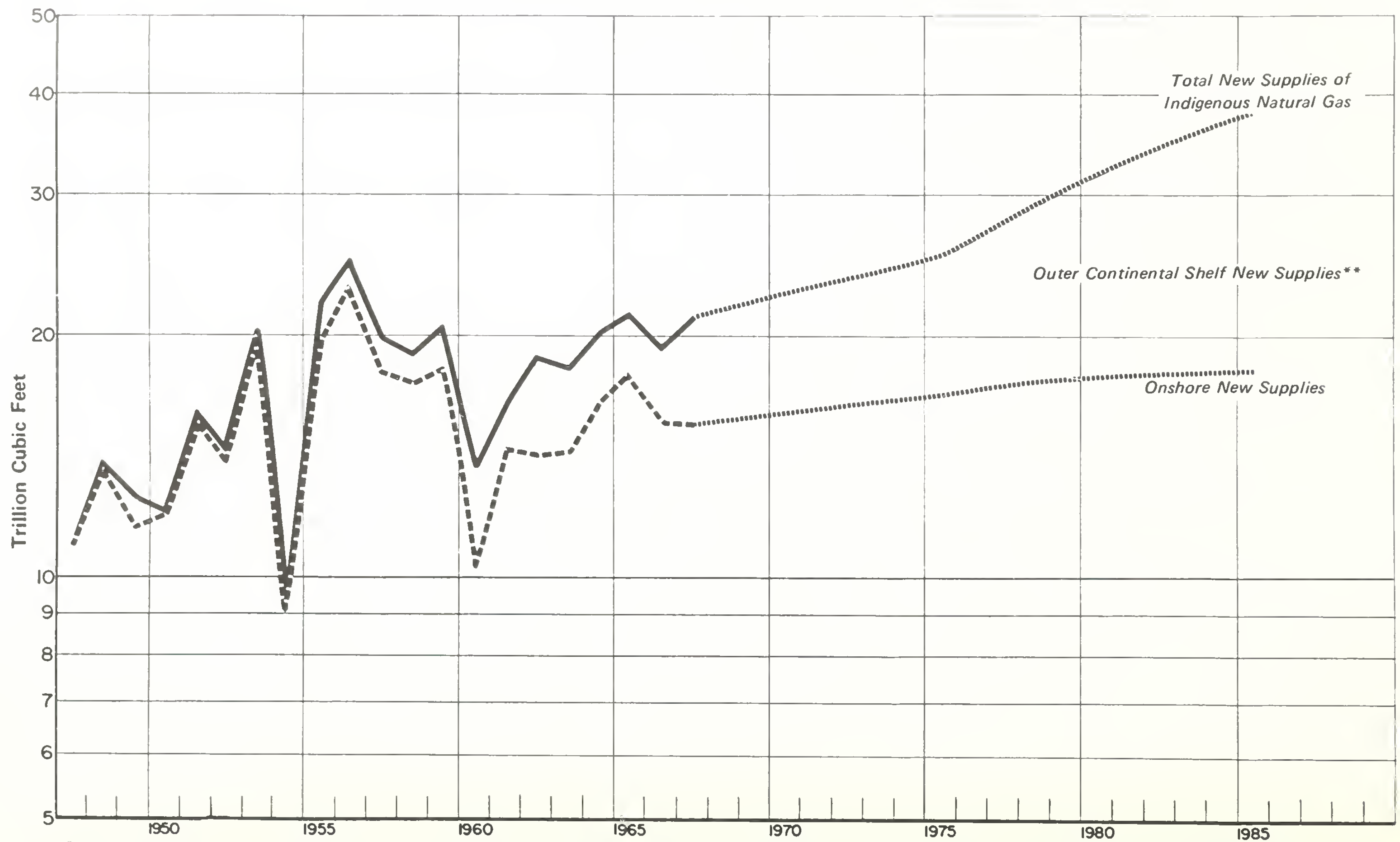
a/ Excludes Alaska.

ESTIMATED SOURCES OF NATURAL GAS TO MEET PROJECTED REQUIREMENTS TO 1985*



*Excludes Alaska

ESTIMATED NEW SUPPLIES OF INDIGENOUS NATURAL GAS NECESSARY TO MEET REQUIREMENTS AND MAINTAIN A MINIMUM RESERVE INVENTORY OF 12 YEARS*



*Excludes Alaska

**Includes the Gulf of Mexico, the Pacific OCS and, hypothetically, the Atlantic OCS

PETROLEUM SUPPLY AND DEMAND[a]
IN THE UNITED STATES

1951 - 1967

(Thousand Barrels per Day)

Year	Domestic Product Demand	NGL Production	Product Imports (Net)	Refinery Gain, Etc.[b]	Crude Oil Exports	Crude Oil			Lease[c] Condensate Production	Net Crude Oil Production		
						Requirements	Gross Imports	Production		Total	OCS	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1951	7,016	561	11	(126)	79	6,649	491	6,158	170	5,988	13	5,975
1952	7,290	611	20	(97)	73	6,829	573	6,256	167	6,089	16	6,073
1953	7,600	654	40	(145)	54	7,105	647	6,458	175	6,283	19	6,264
1954	7,735	690	78	5	37	6,999	656	6,343	134	6,209	31	6,178
1955	8,455	771	130	(3)	31	7,588	782	6,806	107	6,699	56	6,643
1956	8,776	800	150	(181)	78	8,085	934	7,151	145	7,006	95	6,911
1957	8,811	808	122	(173)	138	8,192	1,022	7,170	156	7,014	127	6,887
1958	9,118	807	484	176	12	7,663	953	6,710	129	6,581	138	6,443
1959	9,526	879	610	25	7	8,019	966	7,053	175	6,878	172	6,706
1960	9,797	929	607	220	9	8,050	1,015	7,035	249	6,786	207	6,579
1961	9,976	991	707	59	9	8,228	1,045	7,183	274	6,909	245	6,664
1962	10,400	1,021	792	134	5	8,458	1,126	7,332	266	7,066	304	6,762
1963	10,743	1,098	788	188	4	8,673	1,131	7,542	315	7,227	357	6,870
1964	11,023	1,155	862	197	3	8,812	1,198	7,614	311	7,303	418	6,885
1965	11,512	1,210	1,046	217	3	9,042	1,238	7,804	310	7,494	478	7,016
1966	12,084	1,284	1,154	130	4	9,520	1,225	8,295	329	7,966	582	7,384
1967	12,560	1,409	1,175	111	73	9,938	1,128	8,810	356	8,454	716	7,738

a/ Data are on a 48-state basis prior to 1959, 50-state basis from 1959 on.

b/ Includes stock changes, unfinished oil rerun at refineries, crude oil losses and other miscellaneous items.

c/ Represents difference between natural gas liquids production as reported by American Petroleum Institute, and natural gas liquids production as reported by Bureau of Mines, U. S. Department of the Interior.

Source: Bureau of Mines, U. S. Department of the Interior.
American Petroleum Institute (API).
Annual reports of the Louisiana State Department of Conservation.
Annual reports of the Texas Railroad Commission.

PETROLEUM SUPPLY AND DEMAND
P.A.D. DISTRICTS I AND II
1955 AND 1960-1967
(Thousand Barrels per Day)

	1955 (1)	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)
District Product Demand	5,822	6,756	6,835	7,130	7,355	7,493	7,843	8,228	8,579
NGL Production	133	174	184	186	204	217	226	237	240
Product Imports (Net)	410	676	733	808	858	919	1,063	1,182	1,242
Product Shipments from Other Districts (Net)	1,945	2,142	2,294	2,390	2,474	2,501	2,574	2,694	2,901
Refinery Gain, etc.[a]	(8)	139	(48)	61	36	87	160	35	73
Crude Oil Shipments to Other Districts[b]	26	22	32	18	13	9	1	1	3
Crude Oil Requirements	3,368	3,647	3,704	3,703	3,796	3,778	3,821	4,081	4,126
Crude Oil Production	1,328	1,352	1,357	1,391	1,359	1,360	1,331	1,362	1,339
Crude Oil Gross Imports	659	731	734	764	775	794	821	843	749
Crude Oil Shipments from Other Districts	1,381	1,564	1,613	1,548	1,662	1,624	1,669	1,876	2,038

a/ Includes stock changes, unfinished oils rerun at refineries, crude oil losses and other miscellaneous items.

b/ Includes exports.

Source: Bureau of Mines, U.S. Department of the Interior.

PETROLEUM SUPPLY AND DEMAND

P.A.D. DISTRICT III

1955 AND 1960-1967

(Thousand Barrels per Day)

	1955	1960	1961	1962	1963	1964	1965	1966	1967
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
District Product Demand	1,277	1,450	1,480	1,574	1,637	1,701	1,775	1,842	1,878
NGL Production	545	647	700	729	790	838	888	951	1,072
Product Imports (Net)	(146)	(30)	(26)	(27)	(50)	(47)	(33)	(54)	(90)
Product Shipments from Other Districts (Net)	(1,934)	(2,189)	(2,328)	(2,433)	(2,522)	(2,576)	(2,666)	(2,808)	(3,041)
Refinery Gain, etc.a/	(73)	50	84	95	99	59	30	33	14
Crude Oil Shipments to Other Districtsb/	1,193	1,238	1,299	1,265	1,356	1,357	1,395	1,612	1,858
Crude Oil Requirements	4,078	4,210	4,349	4,475	4,676	4,784	4,951	5,332	5,781
Crude Oil Production	4,040	4,166	4,295	4,440	4,652	4,767	4,944	5,324	5,770
Crude Oil Gross Imports	30	8	6	7	5	5		1	2
Crude Oil Shipments from Other Districts	8	36	48	28	19	12	7	7	9

a/ Includes stock changes, unfinished oils rerun at refineries, crude oil losses and other miscellaneous items.

b/ Includes exports.

Source: Bureau of Mines, U. S. Department of the Interior.

PETROLEUM SUPPLY AND DEMAND
P.A.D. DISTRICT IV
1955 AND 1960-1967
(Thousand Barrels Per Day)

	1955	1960	1961	1962	1963	1964	1965	1966	1967
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
District Product Demand	259	277	302	310	319	320	325	351	354
NGL Production	10	32	33	33	32	31	31	31	33
Product Imports (Net)							2	3	2
Product Shipments from Other Districts (Net)	(8)	(33)	(25)	(23)	(26)	(33)	(40)	(28)	(35)
Refinery Gain, etc.a/	(11)	(5)	8	(3)	7	4	29	32	12
Crude Oil Shipments to Other Districtsb/	198	399	407	360	382	331	340	324	304
Crude Oil Requirements	466	682	693	663	688	649	643	637	646
Crude Oil Production	466	681	692	660	677	636	630	623	628
Crude Oil Gross Imports				2	10	12	13	14	18
Crude Oil Shipments from Other Districts		1	1	1	1	1			

a/ Includes stock changes, unfinished oils rerun at refineries, crude oil losses and other miscellaneous items.
b/ Includes exports.

Source: Bureau of Mines, U.S. Department of the Interior.

PETROLEUM SUPPLY AND DEMAND
P.A.D. DISTRICT V
1955 AND 1960-1967

(Thousand Barrels Per Day)

	1955	1960	1961	1962	1963	1964	1965	1966	1967
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
District Product Demand	1,097	1,314	1,358	1,386	1,432	1,509	1,569	1,663	1,749
NGL Production	84	77	74	73	72	69	65	65	64
Product Imports (Net)	(134)	(39)		11	(20)	(10)	14	24	21
Product Shipments from Other Districts (Net)	(3)	80	59	66	74	108	132	142	175
Refinery Gain, etc.a/	8	35	14	(19)	47	48	(1)	29	12
Crude Oil Shipments to Other Districtsb/	3	13	6	3	4	3	1	2	5
Crude Oil Requirement	1,065	1,174	1,217	1,258	1,263	1,297	1,360	1,405	1,482
Crude Oil Production	972	836	839	841	854	851	899	986	1,073
Crude Oil Gross Imports	93	276	305	353	341	387	404	367	359
Crude Oil Shipments from Other Districts		62	73	64	68	59	57	52	50

a/ Includes stock changes, unfinished oils rerun at refineries, crude oil losses and other miscellaneous items.

b/ Includes exports.

Source: Bureau of Mines, U. S. Department of the Interior.

IMPORTS AS A SOURCE OF U.S. PETROLEUM SUPPLY
1951 - 1968

(Thousand Barrels Per Day)

Year	Total Supply[a]	Gross Imports				Gross Imports as a Percent of Total Supply
		Crude Oil	Residual Fuel	Other Products	Total	
	(1)	(2)	(3)	(4)	(5)	(6)
1951	7,563	491	326	27	844	11.2
1952	7,819	573	351	28	952	12.2
1953	8,146	647	360	27	1,934	12.7
1954	8,085	656	354	42	1,052	13.0
1955	8,825	782	417	49	1,248	14.1
1956	9,387	934	445	57	1,436	15.3
1957	9,552	1,022	475	77	1,574	16.5
1958	9,217	953	499	248	1,700	18.4
1959	9,712	966	610	204	1,780	18.3
1960	9,779	1,015	637	163	1,815	18.6
1961	10,091	1,045	667	205	1,917	19.0
1962	10,435	1,126	724	232	2,082	20.0
1963	10,763	1,131	747	245	2,123	19.7
1964	11,027	1,198	808	252	2,258	20.5
1965	11,482	1,238	946	284	2,468	21.5
1966	12,152	1,225	1,032	316	2,573	21.2
1967	12,756	1,128	1,084	325	2,537	19.9
1968	13,451	1,267	1,526		2,793	20.8

[a] Crude oil production plus natural gas liquids production plus gross imports of all oils.

Source: Bureau of Mines, U. S. Department of the Interior.
1968 - Preliminary Estimate, American Petroleum Institute.

TREND IN OIL WELL DRILLING
UNITED STATES[a)]

1947 - 1967

a) Excludes Alaska where listed separately

TREND IN RESERVE–TO–PRODUCTION RATIO
AND NEW SUPPLY–TO–PRODUCTION RATIO
FOR CRUDE OIL*

UNITED STATES

1947-1967

*Excludes lease condensate

NEW SUPPLY, PRODUCTION AND PROVED RESERVES OF CRUDE OIL
IN THE UNITED STATES[a]
1947-1967

(Millions of Barrels)

Year	Reported Data: New Supply	Reported Data: Net Production	Ratio of New Supply to Net Production: Annual	Ratio of New Supply to Net Production: Three-Year Moving Average[b]	Proved Reserves, End of Year	Reserve-Production Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
1947	2,465	1,850	1.3		21,488	11.6
1948	3,795	2,002	1.9	1.7	23,280	11.6
1949	3,188	1,819	1.8	1.7	24,649	13.6
1950	2,563	1,944	1.3	1.7	25,268	13.0
1951	4,414	2,214	2.0	1.5	27,468	12.4
1952	2,749	2,257	1.2	1.5	27,961	12.4
1953	3,296	2,312	1.4	1.3	28,945	12.5
1954	2,873	2,257	1.3	1.3	29,561	13.1
1955	2,871	2,419	1.2	1.2	30,012	12.4
1956	2,974	2,552	1.2	1.1	30,435	11.9
1957	2,425	2,559	0.9	1.1	30,300	11.8
1958	2,608	2,373	1.1	1.2	30,536	12.9
1959	3,667	2,483	1.5	1.2	31,719	12.8
1960	2,365	2,471	1.0	1.2	31,613	12.8
1961	2,658	2,512	1.1	1.0	31,759	12.6
1962	2,181	2,550	0.9	0.9	31,389	12.3
1963	2,174	2,593	0.8	0.9	30,970	11.9
1964	2,665	2,644	1.0	1.0	30,990	11.7
1965	3,048	2,686	1.1	1.1	31,352	11.7
1966	2,964	2,864	1.0	1.0	31,452[c]	11.0
1967	2,962	3,038	1.0		31,377[c]	10.3

[a] Excludes lease condensate; includes offshore.

[b] Based on three-year moving average of data in Cols. (1) and (2), centered on the middle year.

[c] Excludes additional known reserves considered economically available by application of fluid injection, amounting to 7,594 million barrels in 1966, increasing the RPR to 13.6; and 7,622 million barrels in 1967, increasing the RPR to 12.8.

Source: Reports by the American Petroleum Institute Committee on Crude Oil Reserves.

PRODUCTION, NEW SUPPLIES AND TOTAL RESERVES OF CRUDE OIL IN THE GULF OF MEXICO
1948 - 1967

(Millions of Barrels)

Year	Production[a] La.	Production[a] Tex.	Production[a] Total	New Supply La.	New Supply Tex.	New Supply Total	Reserves La.	Reserves Tex.	Reserves Total	Reserve-Production Ratio Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1948	0.3		0.3	10.0		10.0	16.6		16.6	55.3
1949	0.8		0.8	12.8		12.8	28.6		28.6	35.8
1950	2.7		2.7	36.5		36.5	62.4		62.4	23.1
1951	4.8		4.8	29.1		29.1	86.7		86.7	18.1
1952	6.0		6.0	54.0		54.0	134.7		134.7	22.5
1953	7.0		7.0	35.0		35.0	162.7		162.7	23.2
1954	11.4		11.4	108.4	0.5	108.9	259.7	0.5	260.2	22.8
1955	20.1	0.2	20.3	257.0	0.5	257.5	496.6	0.8	497.4	24.5
1956	34.7	0.1	34.8	288.9	0.5	289.4	750.8	1.2	752.0	21.6
1957	46.0	0.3	46.3	213.9	0.5	214.4	918.7	1.4	920.1	19.9
1958	49.9	0.4	50.3	157.9	0.5	158.4	1,026.7	1.5	1,028.2	20.4
1959	62.6	0.3	62.9	263.6	0.5	264.1	1,227.7	1.7	1,229.4	19.5
1960	75.5	0.3	75.8	185.1		185.1	1,337.3	1.4	1,338.7	17.7
1961	89.1	0.4	89.5	292.1		292.1	1,540.3	1.0	1,541.3	17.2
1962	110.4	0.4	110.8	229.4	1.0	230.4	1,659.3	1.6	1,660.9	15.0
1963	130.0	0.4	130.4	248.3	1.0	249.3	1,777.6	2.2	1,779.8	13.6
1964	152.9	0.2	153.1	389.4	1.0	390.4	2,014.1	3.0	2,017.1	13.2
1965	174.2	0.2	174.4	261.6	1.5	263.1	2,101.5	4.3	2,105.8	12.1
1966	212.0	0.5	212.5	382.3	3.0	385.3	2,271.8	6.8	2,278.6	10.7
1967	254.0	1.5	255.5	347.5	4.2	351.7	2,365.3	9.5	2,374.8	9.3

[a] Excluding lease condensate.

Source: Estimated analysis of data reported by American Petroleum Institute Reserves Committee, the Louisiana State Department of Conservation, and the Texas Railroad Commission. The statistical techniques used in making these estimates are described in Section II of the present Report.

NOTE: American Petroleum Institute's definition of the Gulf of Mexico used, i.e., Louisiana seaward of the Chapman Line and in Texas seaward of the Coast Line.

PRODUCTION OF CRUDE OIL BY P. A. D. DISTRICTS[a/]
1956 COMPARED WITH 1967
(Million of Barrels)

P.A.D. Districts[b/]	Production 1956 (1)	Production 1967 (2)	Percent of Total U. S. Production 1956 (3)	Percent of Total U. S. Production 1967 (4)
I	13	10	0.5	0.3
II	493	468	19.3	15.5
III	1,505	1,935	59.0	63.8
IV	189	232	7.4	7.6
V	351	388	13.8	12.8
Total U. S.	2,552	3,038	100.0	100.0

a/ Excluding lease condensate.

b/ The source shows several states grouped in a miscellaneous category for both 1956 and 1967 which are included in the total but not in the District breakdown. For District I: Florida and Virginia; for District II: Missouri, South Dakota and Tennessee; for District V: Arizona and Nevada. Alaska is included in District V in 1967, but is not included in 1956.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

CRUDE OIL RESERVES BY P.A.D. DISTRICTS
1956 COMPARED WITH 1967

(Millions of Barrels)

P. A. D. Districts[a/]	Reserves: Proved 1956 (1)	Reserves: Proved 1967 (2)	Reserves: Indicated Additional[b/] 1967 (3)	Percent of: Total Proved Reserves 1956 (4)	Percent of: Total Proved Reserves 1967 (5)	Percent of: Indicated Additional Reserves 1967 (6)	Reserve-Production Ratio: Based on Proved Reserves 1956 (7)	Reserve-Production Ratio: Based on Proved Reserves 1967 (8)	Reserve-Production Ratio: Based on Total Reserves (Col.2+Col.3) 1967 (9)
I	226	134	103	0.7	0.4	1.3	17.1	13.5	23.9
II	4,296	3,091	697	14.1	9.9	9.1	8.7	6.6	8.1
III	20,018	21,488	3,549	65.8	68.5	46.6	13.3	11.1	12.9
IV	2,120	1,892	477	7.0	6.0	6.3	11.2	8.2	10.2
V	3,771	4,750	2,796	12.4	15.1	36.7	10.8	12.2	19.4
Total U.S.	30,435	31,377	7,622	100.0	100.0	100.0	11.9	10.3	12.8

a/ The source shows several states grouped in a miscellaneous category for both 1956 and 1967 which are included in the total but not in the District breakdown. For District I: Florida and Virginia; for District II: Missouri, South Dakota and Tennessee; for District V: Arizona and Nevada. Alaska is included in District V in 1967 but is not included in 1956.

b/ Additional known reserves considered economically available by application of fluid injection.

Source: Reports by the American Petroleum Institute Committee on Petroleum Reserves.

OIL WELL DRILLING ACTIVITY BY P.A.D. DISTRICTS
1956 COMPARED WITH 1967

P. A. D. Districts	Exploratory 1956	Exploratory 1967	Development 1956	Development 1967	Total Oil Well Completions 1956	Total Oil Well Completions 1967
	(1)	(2)	(3)	(4)	(5)	(6)
I	2	11	705	723	707	734
II	844	424	9,787	4,292	10,631	4,716
Oklahoma	185	62	4,387	1,498	4,572	1,560
III	1,243	441	15,409	6,292	16,652	6,733
Louisiana	146	93	1,741	1,233	1,887	1,326
Texas	949	274	12,059	4,175	13,008	4,449
IV	91	124	914	556	1,005	680
Wyoming	17	64	447	274	464	338
V[a]	87	39	1,559	2,144	1,646	2,183
California	87	39	1,559	2,102	1,646	2,141

[a] Alaska is not included in 1956, but is included in 1967.

Source: Total Wells - World Oil, Annual Forecast - Review Issues.
Exploratory Wells - American Association of Petroleum Geologists, Statistics of Exploratory Drilling in the United States, and Bulletin of the American Association of Petroleum Geologists.
Development Wells - Total Wells minus Exploratory Wells.

PRODUCTION OF NATURAL GAS LIQUIDS
IN P. A. D. DISTRICTS
1956 COMPARED WITH 1967
(Millions of Barrels)

P. A. D. Districts	Production 1956	Production 1967	Percent of Total U. S. Production 1956	Percent of Total U. S. Production 1967
	(1)	(2)	(3)	(4)
I	4.9	6.7	1.4	1.0
II	41.3	68.0	11.9	10.6
III[a]	263.4	533.7	76.1	82.8
IV	5.0	13.0	1.5	2.0
V[a]	30.4	23.1	8.8	3.6
Total U. S.	346.0[b]	644.5	100.0	100.0

[a] Includes offshore.

[b] Includes one million barrels attributed to Alabama, Florida and North Dakota, Districts III, I and II amounting to 0.3 percent of Total U.S.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NATURAL GAS LIQUID RESERVES IN P. A. D. DISTRICTS 1956 COMPARED WITH 1967

(Millions of Barrels)

P. A. D. Districts	Proved Reserves End of Year		Percent of Total U.S. Proved Reserves		Reserve-Production Ratio	
	1956	1967	1956	1967	1956	1967
	(1)	(2)	(3)	(4)	(5)	(6)
I	29.9	82.8	0.5	1.0	6.1	12.4
II	560.6	852.4	9.5	9.9	13.6	12.5
III[a]	4,907.4	7,297.8	83.1	84.7	18.6	13.7
IV	73.7	162.7	1.3	1.9	14.7	12.5
V[a]	311.7	218.6	5.3	2.5	10.3	9.5
Total U.S.	5,902.3[b]	8,614.3	100.0	100.0	17.1	13.4

[a] Includes offshore.

[b] Includes 19.0 million barrels attributed to Alabama, Florida and North Dakota, Districts III, I and II amounting to 0.3 percent of Total U.S.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

NATURAL GAS LIQUIDS PRODUCTION OFFSHORE LOUISIANA

(Thousands of Barrels)

Year	Production
Total Production through 1951	54
Annual	
1952	281
1953	332
1954	547
1955	844
1956	822
1957	701
1958	1,456
1959	2,436
1960	3,555
1961	4,823
1962	6,913
1963	8,796
1964	10,054
1965	14,033
1966	20,505

Source: Louisiana Department of Conservation, Annual Oil and Gas Reports.

NEW SUPPLY, NET PRODUCTION AND PROVED RESERVES OF NATURAL GAS LIQUIDS IN THE UNITED STATES[a/]
TOTAL ALL TYPES[b/]

1947-1967
(Millions of Barrels)

Year	Reported Data		Ratio of New Supply to Net Production		Proved Reserves, End of Year	Reserve-Production Ratio
	New Supply	Net Production	Annual	Three-Year Moving Average[c/]		
	(1)	(2)	(3)	(4)	(5)	(6)
1947	252	161	1.6		3,254	20.2
1948	471	184	2.6	2.0	3,541	19.2
1949	387	199	1.9	2.7	3,729	18.7
1950	766	227	3.4	2.7	4,268	18.8
1951	724	267	2.7	2.6	4,725	17.7
1952	557	285	2.0	2.4	4,997	17.5
1953	744	303	2.5	1.6	5,438	17.9
1954	107	301	0.4	1.5	5,244	17.4
1955	515	320	1.6	1.5	5,439	17.0
1956	810	346	2.3	1.4	5,902	17.1
1957	137	352	0.4	1.7	5,687	16.2
1958	858	342	2.5	1.6	6,204	18.1
1959	703	385	1.8	2.0	6,522	16.9
1960	725	431	1.7	1.7	6,816	15.8
1961	695	462	1.5	1.6	7,049	15.3
1962	733	470	1.6	1.6	7,312	15.6
1963	878	516	1.7	1.5	7,674	14.9
1964	609	536	1.1	1.4	7,747	14.5
1965	832	555	1.5	1.4	8,024	14.5
1966	894	589	1.5	1.5	8,329	14.1
1967	930	644	1.4		8,614	13.4

a/ Includes offshore.

b/ Includes lease condensate, natural gasoline and liquefied gases.

c/ Based on three-year moving average of data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

RELATIONSHIP OF NATURAL GAS LIQUIDS RESERVES AND NATURAL GAS RESERVES IN THE UNITED STATES[a]

1947-1967

Year	Natural Gas Year-End Proved Reserves: Non-Associated	Associated-Dissolved	Underground Storage	Total	Natural Gas Liquids Year-End Proved Reserves: Non-Associated	Associated-Dissolved	Total	Barrels of Natural Gas Liquids Reserves per MMcf of Natural Gas Reserves: Non-Associated	Associated-Dissolved	Total
	(Trillions of Cubic Feet @ 14.73 Psia)				(Millions of Barrels)					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1947	119.1	45.9	b/	165.0	1.9	1.3	3.2	16.19	28.87	19.72
1948	122.7	50.0	0.2	172.9	2.0	1.5	3.5	16.49	30.36	20.48
1949	125.4	53.7	0.3	179.4	2.1	1.6	3.7	16.78	30.26	20.79
1950	129.9	54.3	0.3	184.5	2.4	1.9	4.3	18.26	34.89	23.12
1951	133.0	59.2	0.5	192.7	2.4	2.3	4.7	18.07	39.17	24.51
1952	136.9	61.0	0.7	198.6	2.4	2.6	5.0	17.62	42.33	25.16
1953	146.0	63.0	1.2	210.3	2.7	2.7	5.4	18.69	42.94	25.86
1954	145.3	64.0	1.3	210.6	2.6	2.6	5.2	18.23	40.56	24.90
1955	151.2	69.9	1.4	222.5	2.6	2.8	5.4	17.32	40.33	24.44
1956	159.2	75.8	1.5	236.5	2.8	3.1	5.9	17.65	40.78	24.96
1957	167.6	76.0	1.7	245.2	2.7	3.0	5.7	16.15	39.23	23.19
1958	176.9	74.1	1.7	252.7	3.2	3.0	6.2	18.26	40.10	24.54
1959	183.2	76.1	1.9	261.2	3.4	3.1	6.5	18.66	40.79	24.97
1960	185.3	74.8	2.2	262.3	3.7	3.1	6.8	19.90	41.80	25.98
1961	190.7	73.3	2.3	266.3	3.8	3.2	7.0	20.20	43.63	26.47
1962	198.7	71.1	2.5	272.3	4.2	3.1	7.3	21.33	43.23	26.85
1963	201.2	72.2	2.7	276.1	4.6	3.1	7.7	22.72	42.98	27.79
1964	207.1	71.2	2.9	281.2	4.8	2.9	7.7	23.14	41.51	27.54
1965	213.3	70.1	3.1	286.5	5.0	3.0	8.0	23.63	42.58	28.01
1966	217.4	68.7	3.2	289.3	5.2	3.1	8.3	24.05	45.13	28.79
1967	221.7	67.8	3.4	292.9	5.6	3.0	8.6	25.14	44.83	29.41

a/ Includes offshore.

b/ Not estimated.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

UNITED STATES PETROLEUM SUPPLY AND DEMAND MODEL

(Thousand Barrels Per Day)

			Projections		
	1965	1975	1985		
			Case A		Case B
	(1)	(2)	(3)		(4)
Domestic Product Demand	11,512	16,200	21,300		20,700
Natural Gas Liquids	1,210	1,888		2,500	
Product Imports (Net)[a]	1,046	1,728	2,600		2,000
Refinery Gain, etc.	217	618		950	
Crude Oil Requirements	9,039	11,966		15,250	
Crude Oil Imports (Net)[a]	1,235	1,459	1,660		2,140
Crude Oil Production	7,804	10,507	13,590		13,110

[a]Product and crude imports projected at approximately 20 percent of domestic demand.

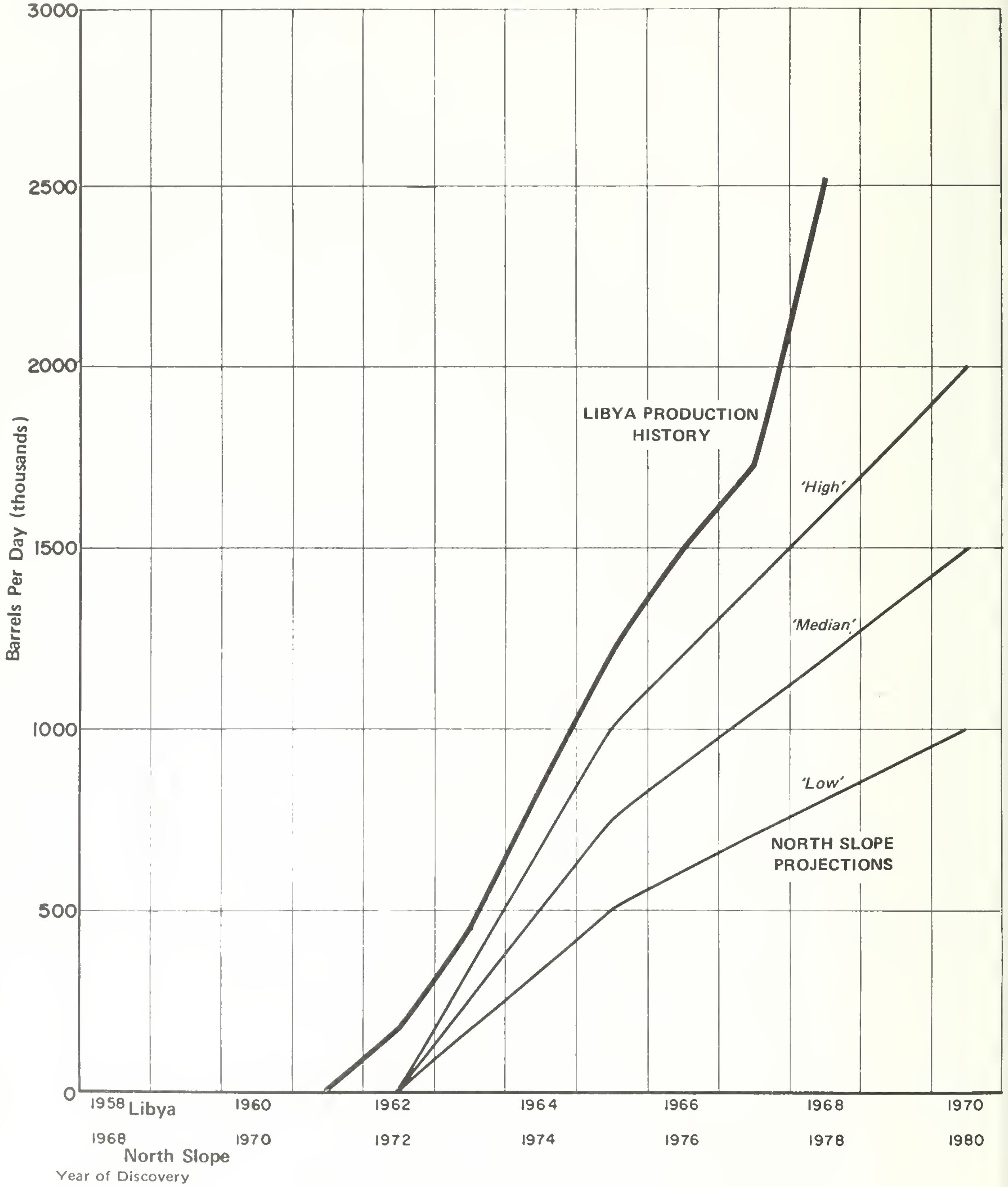
COMPARISON OF PRODUCTIVE CAPACITY AND PRODUCTION IN 1968

(Thousand Barrels Per Day)

P. A. D. District	Productive Capacity (1)	Production (Average Jan.-Jun.1968) (2)	Excess Capacity (3)
I	31	28	3
II	1,287	1,267	20
III			
Louisiana	3,005	2,230	775
Texas	4,301	3,172	1,129
Other	601	582	19
IV	663	658	5
V	1,330	1,201	129
Total U.S.	11,218	9,138	2,080

Source: IPAA Productive Capacity Committee; Bureau of Mines, U.S. Department of the Interior.

COMPARISON OF NORTH SLOPE PRODUCTION WITH COMPARABLE DEVELOPMENT OF PRODUCTION FROM LIBYA



POTENTIAL IMPACT OF PROJECTED NORTH SLOPE CRUDE OIL PRODUCTION[a] ON DOMESTIC RESERVES

Year	Domestic Crude Oil Requirements	Projected North Slope Production			Production Requirements on Other Domestic Reserves			
					If No North Slope	With North Slope		
		"Low"	"Medium"	"High"		"Low"	"Medium"	"High"
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	(Millions of Barrels)							
1967	3,038				3,038	3,038	3,038	3,038
1975	3,640	183	274	365	3,640	3,457	3,366	3,275
1985	4,670	548	821	1,095	4,670	4,122	3,849	3,575

Year	Proven and Indicated Domestic Reserves, Excluding North Slope				Reserve-Production Ratio, Excluding North Slope Reserves			
	If No North Slope Production	With North Slope Production			If No North Slope Production	With North Slope Production		
		"Low"	"Medium"	"High"		"Low"	"Medium"	"High"
	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	(Billions of Barrels)							
1967	39.0	39.0	39.0	39.0	12.8	12.8	12.8	12.8
1975	40.4	40.7	40.8	41.0	11.1	11.8	12.1	12.5
1985	38.1	40.3	41.4	42.5	8.2	9.8	10.7	11.9

[a] Excludes lease condensate.

PROJECTED NATURAL GAS LIQUIDS PRODUCTION

BY P.A.D. DISTRICTS AND OCS[a]

1975 AND 1985

(Millions of Barrels)

P. A. D.	1965			1975			1985		
District	Onshore	OCS	Total	Onshore	OCS	Total	Onshore	OCS	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
I	8		8	11		11	11	18[b]	29
II	51		51	75		75	77		77
III	429	30	459	577	180	757	648	380	1,028
IV	13		13	14		14	14		14
V	24	—	24	21	5	26	21	15	36
Total U.S.	525	30	555	698	185	883	771	413	1,184

[a] Includes lease condensate.

[b] Assuming commercial gas production is established in the Atlantic OCS. See Chapter B for details.

DISTRICT V SUPPLY AND DEMAND MODEL
(Thousand Barrels per Day)

		Projections	
	1965	1975	1985[a]
	(1)	(2)	(3)
Product Demand	1,569	2,380	3,360
Natural Gas Liquids Production	65	77	123
Product Imports (Net)	14	(27)	
Product Shipments from Other Districts (Net)	132	150	141
Refinery Gain, etc.	(1)	126	236
Crude Oil Shipments from District	1		
Crude Oil Requirements	1,360	2,054	2,860
Crude Oil Production:			
A. California, Cook Inlet, etc.	889	1,280	1,220
B. North Slope at:			
1. "low" projection		500	1,500
2. "medium" projection		750	2,250
3. "high" projection		1,000	3,000
Crude Oil Shipments from North Slope to Districts I and II			
1. "low" projection			
2. "medium" projection		76	710
3. "high" projection		326	1,460
Crude Oil Shipments from Other Districts	57		
Crude Oil Imports (Net)[b] with North Slope Production at:	404		
1. "low" projection		274	140
2. "medium" projection		100	100
3. "high" projection		100	100

[a] Cases A and B the same.

[b] Crude oil imports are assumed to bottom at 100 MBD throughout the forecast period.

DISTRICT IV SUPPLY AND DEMAND MODEL
(Thousand Barrels per Day)

		Projections	
	1965	1975	1985 (Case A)
	(1)	(2)	(3)
Product Demand	325	447	585
Natural Gas Liquids Production	31	44	55
Product Shipments to Other Districts (Net)	38	55	68
Refinery Gain, etc.	29	8	23
Crude Oil Shipments to Other Districts	340	260	203
Crude Oil Requirements	643	710	778
Crude Oil Production	630	660	728[a]
Crude Oil Imports	13	50	50[b]

a/ Case B - 628 MBD.

b/ Case B - 150 MBD.

DISTRICTS I AND II SUPPLY AND DEMAND MODEL
(Thousand Barrels per Day)

		Projections		
			1985	
	1965	1975	Case A	Case B
	(1)	(2)	(3)	(4)
Product Demand	7,843	10,900	14,032	13,432
Natural Gas Liquids[a/]	226	559	747	747
Product Imports (Net)	1,063	1,755	2,640	2,040
Product Shipments from Other Districts	2,574	3,380	4,500	4,500
Refinery Gain, etc	160	248	338	338
Crude Oil Shipments from District	1			
Crude Oil Requirements	3,821	4,958	5,807	5,807
Crude Oil Production	1,331	1,213	1,147	767
Crude Oil Shipments from District IV	274	260	203	203
Crude Oil Imports with North Slope Production at:	821			
1. "low" projection		1,135	1,432	1,812
2. "medium" projection		1,309	1,472	1,852
3. "high" projection		1,315	1,472	1,852
Crude Oil Shipments from North Slope with Production at:				
1. "low" projection				
2. "medium" projection		76	710	710
3. "high" projection		326	1,460	1,460
Crude Oil Shipments From District III with North Slope at:	1,395			
1. "low" projection		2,350	3,025	3,025
2. "medium" projection		2,100	2,275	2,275
3. "high" projection		1,844	1,525	1,525

a/ Includes Inter-District Shipments in 1975 and 1985.

SOURCE OF CRUDE OIL SUPPLIES FOR DISTRICTS I AND II

(Percent)

	1965 (1)	1985 (2)
Local Production and District IV Shipments	42	22 - 16
Imports	22	25 - 32
North Slope		0 -25
District III	36	53 - 27
Total	100	100

DISTRICT III SUPPLY AND DEMAND MODEL
(Thousand Barrels per Day)

		Projections	
	1965 (1)	1975 (2)	1985[a] (3)
Product Demand	1,775	2,473	3,323
Natural Gas Liquids[b]	888	1,208	1,597
Product Exports (Net)	33		
Product Shipments to Other Districts	2,666	3,471	4,569
Refinery Gain, etc.	30	236	353
Crude Oil Shipments to Districts I & II with North Slope at:	1,395		
1. "low" projection		2,350	3,025
2. "medium" projection		2,100	2,275
3. "high" projection		1,844	1,525
Crude Oil Production (Requirements) with North Slope Production at:	4,951[c]		
1. "low" projection		6,850	8,967
2. "medium" projection		6,600	8,217
3. "high" projection		6,350	7,467

a/ Cases A and B the same.

b/ Excludes shipments to other districts in 1975 and 1985.

c/ Includes seven thousand barrels per day from other districts.

IMPACT OF NORTH SLOPE AND OCS CRUDE OIL PROJECTIONS
ON ONSHORE DISTRICT III PRODUCTION

(Thousand Barrels per Day)

	1970	1975	1980	1985
	(1)	(2)	(3)	(4)
1. Total OCS Production				
a. "low" North Slope	1,035	1,535	2,040	2,550
b. "medium" North Slope	1,035	1,535	1,990	2,450
c. "high" North Slope	1,035	1,535	1,940	2,350
2. California OCS Production				
a. "low" North Slope	75	300	400	500
b. "medium" North Slope	75	300	350	400
c. "high" North Slope	75	300	300	300
3. Gulf of Mexico OCS Production	960	1,220	1,640	2,050
4. District III Crude Oil Requirements	6,119			
a. "low" North Slope		6,850		8,967
b. "medium" North Slope		6,600		8,217
c. "high" North Slope		6,350		7,467
5. Onshore District III Production	5,084			
a. "low" North Slope		5,630		6,917
b. "medium" North Slope		5,380		6,167
c. "high" North Slope		5,130		5,417

SECTION II
The Cost of Finding and Producing Hydrocarbon Supplies

SUMMARY OF FINDINGS AND CONCLUSIONS

At the heart of an evaluation of the prospective contribution of the Outer Continental Shelf to the Nation's energy supplies lies an estimate of the cost and profitability of finding and producing hydrocarbon supplies in comparison with the cost of supplies from other areas. Such comparative cost estimates were made for three separate geographic areas: (1) the Gulf of Mexico, with particular emphasis on offshore Louisiana; (2) onshore South Louisiana, which has similar geological formations to offshore Louisiana, and (3) the remainder of the Continental U.S., embracing the diverse geological formations of the Southwest, Rocky Mountains, California, Midwest, and Appalachian producing areas, but excluding Alaska. For each of these three areas separate cost estimates were made for oil and gas reservoirs,[1] and, on a combined basis, for total hydrocarbons. This study leads to the conclusion that the profitability of the operations in the Gulf of Mexico is higher than for Other Continental U.S., but somewhat lower than for onshore South Louisiana.

The measurement of cost in this study focuses on the "current cost" of new hydrocarbon supplies. By "current cost" is meant the cost which may reasonably be anticipated in the near-term future in the absence of significant changes in discovery rates or other factors influencing unit costs. The essence of the measurement of current cost is to estimate two categories of costs—those of (1) finding and (2) producing the reserves. Estimates of finding costs are made by relating expenditures for the different cost components (drilling and equipping wells, lease acquisitions, geophysical, geological and other exploratory costs) to new supplies (gross reserve additions) during a recent period. The costs of producing the reserves comprise production operating expenses, production taxes, overhead, royalties, and offshore transportation costs; these costs are related to volumes produced from the reservoirs. A summary of the results of the cost estimates is shown below:

[1] Oil reservoirs produce crude oil, associated gas, and associated natural gas liquids; gas reservoirs produce non-associated gas, condensate and other non-associated natural gas liquids. The unit costs shown for oil and gas reservoirs are computed by relating total expenditures to the predominant product of the reservoirs, crude oil and non-associated gas, respectively.

	Finding and Producing Costs		
	Gulf of Mexico[a]	Onshore So. La.	Other Continental U. S.
Finding Costs			
Oil reservoirs ($/bbl.)	1.30 - 1.35	1.19	1.01
Gas reservoirs (¢/Mcf)	7.04 - 7.85	9.10	8.96
Total hydrocarbons[b] ($/bbl.)	1.19	1.17	1.07
Other Costs (excluding return, royalties and income taxes)			
Oil reservoirs ($/bbl.)	.63	.91	.84
Gas reservoirs (¢/Mcf)	4.07	6.06	4.05
Total hydrocarbons[b] ($/bbl.)	.59	.84	.77

a/ The range of costs shown for Gulf of Mexico is due to the imprecision of costs attributable to oil or gas reservoirs on account of the preponderance of multiple completions.

b/ Non-associated gas converted to equivalent barrels of oil on a revenue basis.

The closeness of the finding costs shown in the three areas masks significant differences in the cost components, such as:

- The productivity of the crude oil reservoirs (in terms of reserve additions per foot drilled) is more than twice as high in the Gulf of Mexico as onshore South Louisiana and about two and one-half times as high as in the remaining U.S.
- The productivity of gas reservoirs is more than twice as high in the Gulf of Mexico as onshore South Louisiana and more than four times as high as in the remaining U.S.
- The higher productivity of oil reservoirs is more than offset by the higher drilling cost experienced offshore, so that the lowest drilling cost per barrel is experienced in the remaining U.S. For gas reservoirs, however, the higher productivity in the Gulf of Mexico more than compensates for the higher drilling cost so that the lowest drilling cost per Mcf is experienced offshore.
- The cost of lease acquisitions (bonuses paid for leaseholds) is twice as high in the Gulf of Mexico as onshore. The competitive bidding for federal offshore leases thus eliminates what would otherwise be a substantial profitability differential between offshore and onshore areas.
- The cost of lease facilities in the Gulf of Mexico is about 20 percent below onshore South Louisiana and about 40 percent below the remaining U.S.
- The cost of dry holes in the Gulf of Mexico is about 15 percent below onshore South Louisiana but 10 percent above the remaining U.S.
- The cost of geophysical, geological and other exploratory expenditures in the Gulf of Mexico is 25 percent below onshore South Louisiana and 10 percent below the remaining U.S.
- The "other costs" (principally the cost of producing the reservoirs) are lower in the Gulf of Mexico than onshore primarily because of the absence of production taxes on federal leases.

In addition to the estimates of the level of current costs, this study also sought to provide quantitative measures of the factors affecting costs in the Gulf of Mexico—specifically, the impact of well depth, water depth, and distance from shore on drilling, production and transportation costs. An analysis of these factors suggests that the estimated level of current costs understates the probable level of future costs in the search for hydrocarbons at greater water depths and distances from shore.

To measure the profitability of the search for and production of hydrocarbons requires taking into account both the timing of expenditures and the timing of receipt of revenues. The average time that elapses between the making of expenditures and the receipt of revenues is 2¼ years, as compared to about one year for onshore operations. The waiting period for offshore operations is longer for gas than for oil; in general, it has tended to decline with greater experience in offshore operations and the increasingly larger outlays for lease bonuses which act as a spur to more rapid development. The longer the waiting period, the lower will be the return earned; however, the longer offshore waiting period is partly offset by the more rapid depletion of the reservoirs in the Gulf of Mexico compared to onshore reservoirs, which is particularly pronounced in comparison with the depletion in the U.S. outside South Louisiana.

The most accurate technique of measuring the rate of return on capital outlays is the so-called discounted cash flow method, i.e., the rate which equates the present value of the future stream of revenues with capital outlays, taking into account both the lag between the expenditures and the receipt of revenues, as well as the depletion (production) rate of the reservoirs. The table below shows the discounted cash flow returns indicated by the relationship between the estimated current cost and revenues:

	Estimated Discounted Cash Flow Return		
	Oil Reservoirs	Gas Reservoirs	Total Hydrocarbons
	In percent		
Gulf of Mexico	5.0-5.4	5.7-6.6	5.6
Onshore So. La.	6.4	5.8	6.2
Other Continental U.S.	4.3	3.2	4.0

The profitability of the operations in the Gulf of Mexico is thus below that of onshore South Louisiana operations, but higher than for other U.S. operations. The return on gas reservoirs appears to be below that of oil reservoirs, except for offshore operations; however, these differences may reflect the unavoidable use of discretionary cost allocations.

The discounted cash flow technique measures return by reference to total finding costs, irrespective of whether they are expensed or capitalized on the books of account. The results are therefore not comparable to the usual return measurements computed from financial statements, such as earnings on net investment or book capital. With few exceptions, the discounted cash flow technique will show lower measures of return than the more traditional financial accounting measures. To achieve a measure of comparability, an attempt was made to convert the above discounted cash flow returns into the form of return on book capital. The results show the following:

	Estimated Return on Book Capital		
	Oil Reservoirs	Gas Reservoirs	Total Hydrocarbons
	(In percent)		
Gulf of Mexico	7.2-8.0	8.3-10.4	8.2
Onshore So. La.	11.9	11.0	11.5
Other Continental U.S.	7.2	5.9	6.9

Although the above percentages represent rough approximations, the results confirm the conclusion that the operations in the Gulf of Mexico have not been unduly profitable. The overall rate of profitability of current outlays for finding and producing hydrocarbons is less than the returns on capital experienced in earlier years, and also lies below the approximately 13 - 15 percent return currently earned on book capital by a large segment of U.S. manufacturing enterprises.

In evaluating the significance of the cost and return findings of this study, certian limitations attending these estimates should be borne in mind. Any attempt to estimate the unit cost of finding and producing hydrocarbons is fraught with much uncertainty stemming from both numerous conceptual difficulties and limitations arising from the paucity of data. The resulting unit costs are never a reflection of *the* cost, in the sense of an in-fact cost; they are at best an approximation of *a* cost, reflecting the midpoint of a relatively wide range. Perhaps the severest limitation encountered in the attempt to measure the cost of hydrocarbons is the sparsity of available data on expenditures. That limitation is particularly severe for offshore operations.

A further limitation arises from the fact that only a part of the expenditures data is separately identified with oil or gas reservoirs. This necessitates reliance on discretionary allocation techniques which deprive the' resulting cost estimates for the separate reservoirs of much of their economic significance as a measure of the cost of providing supplies. Thus, the cost estimates for total hydrocarbons are more significant than the cost estimates for the separate reservoirs. However, the former are more significant only in the sense of being more reliable for the purpose of computing the return or cost-revenue relationship; the cost estimates for total hydrocarbons also do not provide an accurate measure of the cost of new supplies because they reflect a conversion of gas into equivalent oil barrels. That conversion was made on a relative revenue basis, which also reflects, of course, the use of discretionary judgment.

Another limitation arises from the fact that, when expenditures are related to reserve additions, one proceeds on the implicit assumption that the reserve additions reported as extensions and revisions are related to the discoveries of the same period, whereas in fact a portion of the extensions and revisions relate to prior year's discoveries.

Other limitations arise from the attempt to identify exploratory expenditures with particular areas, whereas in fact the exploratory effort is national in scope. Furthermore, any unit cost computation related to past reserve additions reflects whatever happens to have been the level of drilling activity. The cost of input factors per unit of reserve additions may be different if the level of activity is expanded or contracted in response to a change in price incentives.

CHAPTER A
SCOPE, METHOD AND LIMITATIONS

I. Geographical Scope

The purpose of this study is to provide comparisons, between offshore and onshore areas, of estimates of the cost of finding and producing hydrocarbons. The areas selected for comparison are (1) offshore Gulf of Mexico, with particular emphasis on offshore South Louisiana, as compared to (2) onshore South Louisiana, and (3) the remainder of the Continental U.S. embracing the Southwest, Rocky Mountain, California, Midwest and Appalachian producing regions, but excluding Alaska and the North Slope. For each of the three major areas, separate cost estimates were made for oil reservoirs and non-associated gas reservoirs and, on a combined basis, for total hydrocarbons.

Offshore production of hydrocarbons is not limited to the Gulf of Mexico; offshore California and Alaska are becoming increasingly significant sources of supply. However, production experience in the latter two areas is of such recent origin, and the available data are so limited as to make it impracticable, if not impossible, to undertake an economic-statistical analysis. In large degree, these observations are also applicable to the offshore Texas portion of the Gulf of Mexico, so that for a number of cost components the analysis had to be limited to offshore South Louisiana.

The choice of onshore South Louisiana as an area for comparison with offshore Gulf of Mexico was governed both by the similarity of geological formations and the fact that, from a technological drilling point of view, the early offshore shallow-water activities were an extension of the marsh and bayou onshore activities. Virtually all of the offshore operators are also heavily engaged in onshore South Louisiana exploration activities, so that the comparative economics of the two areas have a significant influence on the commitment of funds.

During the decade 1958-1967, approximately 80 percent of the Continental U.S. oil and 63 percent of the Continental U.S. gas supplies were found in areas other than the Gulf of Mexico and onshore South Louisiana. These reserve additions were spread throughout the remaining U.S., which have been grouped together for purposes of this study. This grouping was prompted not only by budgetary limitations, but also by the desire to provide a comparative benchmark on as broad a basis as possible. In the costing of hydrocarbons, excessive area fragmentation provides an illusory refinement. Although geological and economic conditions vary widely within the broad area covered by the remaining U.S., exploration is essentially national in scope, and the market for both oil and gas products is also virtually national. The largest possible aggregation of areas therefore provides the most significant measure of the cost of providing supplies.

II. Measurement of Cost

All measurements of costs of hydrocarbons must be regarded as estimates, subject to a wide range of uncertainty due to conceptual and data limitations discussed below. The cost estimates may be made by reference to either the experienced past cost or the current cost, or to a projection of the cost of finding and producing hydrocarbon supplies. The prospective cost is, of course, the economically most meaningful measure of cost because it alone will furnish an indication of the price required to bring forth the supplies. However, no future projection of cost is here undertaken for the reason that it would require a study of prospective technological changes and a projection of probable future discovery rates, both of which are beyond the scope of this study. Instead, the focus in this study is on the current cost of finding supplies. Current cost means the cost which may reasonably be anticipated to prevail in the near-term future in the absence of significant changes of either discovery rates or technology.

The essence of the measurement of a current cost is to estimate the cost of finding and producing the reserves. Estimates of finding costs are made by relating expenditures for the different cost components (drilling and equipping wells, lease acquisitions, geophysical and geological) to reserve additions during a recent period. That period must be of sufficient length to smooth out erratic annual variations in new supplies. The costs of producing the reserves comprise production operating expenses, production taxes, overhead and royalties. Finally, the timing of expenditures and the receipt of revenues is taken into account in estimating the return earned. The results of this study are therefore not a measure of the economic cost of finding new supplies, in the sense of measuring the total cost, including an allowance for return commensurate with the risk, but are instead measures of comparative profitability at present price levels.

Although the intention is to focus on current costs, the limitation of the data renders the results a blend of current and past costs. To illustrate, it is not possible—particularly for the Gulf of Mexico—to

make reliable estimates of reserve additions resulting from drilling activities in a recent five-year period, independent of the level of reserve additions in earlier periods. However, it is possible to estimate the current cost of drilling and equipping the wells. Thus, what is here labelled "current" drilling cost is perhaps more accurately described as the present cost of past reserve additions. Similarly, it is also not possible to take into account the most recent expenditures for lease acquisitions, because insufficient time has elapsed to obtain information on the reserves discovered on these leases. Thus, the results of this study are a more nearly accurate reflection of the present cost of finding the hydrocarbons discovered in the past five to ten years than they are of a forecast of the cost of finding new supplies in the next five years.

In addition to the estimates of the level of current costs, this study also focuses on the factors affecting costs in the Gulf of Mexico; specifically, the impact of well depth, water depth, and distance from shore on drilling, production and transportation costs. An analysis of these factors suggests that the estimated level of current costs understates the probable level of future costs incurred in the search for hydrocarbons at greater water depths and distance from shore.

Throughout this study, each of the cost components has been estimated separately for reservoirs containing primarily oil[1] and for reservoirs containing primarily gas.[2] Approximately 60 percent of total finding and producing expenditures can be directly identified with either oil or gas reservoirs. The remaining 40 percent, comprising dry holes, lease acquisitions, overhead, geophysical, geological and other exploratory expenditures must be treated as joints costs; the separation between oil and gas reservoirs is therefore dependent on wholly discretionary methods of allocation. The resulting total costs attributed to the respective oil and gas reservoirs are thus neither a reflection of in-fact costs, nor can they be regarded as a measure of economic cost in the sense of furnishing a reliable indication of the price or cost of providing additional supplies.

Nevertheless, considerable attention is paid throughout this study to the respective cost (directly identified with or allocated to) oil and gas reservoirs, partly for the reason that the search for hydrocarbons has become increasingly characterized by directionality. The reference to "directionality" is not to the technique of "directional drilling", but to the ability to know, with a high degree of accuracy,[3] whether the exploratory activities are directed to oil- as distinct from gas-bearing formations. Thus, the preponderance of the outlays is no longer made for hydrocarbons but for either oil or gas reservoirs. That development is in part due to advances in technology, but in part also to the increased importance of natural gas, which is no longer a minor product. The economic implications of "directionality" are significant: When a separate search is made for oil or gas reservoirs, the prospective cost of the separate reservoirs—to the extent that it can be *prospectively* directly identified, *ex ante*, not *ex post*—becomes a measure of the price required to elicit supplies.

As previously noted, the direct identification with either oil or gas reservoirs is not presently possible for 40 percent of total expenditures; however, that limitation may be removed as data on identification of dry holes and other exploratory expenditures with oil or gas reservoirs become available. The techniques of cost analysis herein developed can then be refined and an economically more meaningful separate cost of oil and gas reservoirs may be estimated. Of course, the direct identification of expenditures with oil or gas reservoirs will not furnish the cost of either oil or gas as a separate product. Each of these reservoirs produces multiple products[4] which are, and will remain, joint in nature. A separation of the cost of these joint products can be achieved only by wholly arbitrary allocations, which have no economic meaning in the sense of providing a measure of either in-fact cost or the price necessary to elicit the supplies. Such allocations are mere exercises in arithmetic; none are attempted in this study.

III. Limitations

In evaluating the significance of the cost and return findings of this study, the limitations attending these estimates should be borne in mind. While these limitations will become apparent from the more detailed discussion of the techniques used in estimating the individual cost components (Chapter C), a brief summarization may help place the results in perspective.

[1] The primarily oil reservoirs produce crude oil and associated gas which is sold to pipelines as residue gas after extraction of associated gas liquids.

[2] The primarily gas reservoirs produce non-associated gas and condensate. Where the non-associated gas is rich in liquids, non-associated gas liquids are extracted in plants.

[3] Evidence presented before the Federal Power Commission by 12 major producers shows that the accuracy in identifying gas or oil reservoirs prior to discovery was in excess of 80 percent. Docket Nos. AR64-1 and AR64-2, Exhibit 1-J.

[4] See footnotes 1 and 2 above.

Any attempt to estimate the unit cost of finding and producing hydrocarbons is fraught with much uncertainty. The results are never a reflection of *the* cost, in the sense in which the term cost is understood in industrial engineering or accounting studies; they are at best an approximation of *a* cost, reflecting the midpoint of a relatively wide range. The reasons for this uncertainty stem from both conceptual difficulties and limitations arising from the paucity of data.

Perhaps the severest limitation encountered in the attempt to measure the cost of hydrocarbons is the sparsity of available data on expenditures. That limitation is particularly severe for offshore operations. Data on expenditures in the Gulf of Mexico are available only for drilling, lease acquisition costs, and geophysical costs. Consequently, a confidential special data collection effort was made through the cooperation of 10 companies to ascertain the level of lease equipping cost, production operating expenses, and transportation cost, as well as the impact of well depth, water depth, and distance from shore on selected cost items. Although the companies cooperating in this data gathering project account for over half of hydrocarbon production in the Gulf of Mexico, there is no assurance that these costs are representative of the industry's cost.

The paucity of data is not limited to the Gulf of Mexico. For most cost components, expenditure data are available only on a national basis, so that extensive recourse to estimating procedures was necessary to determine expenditures attributable to onshore South Louisiana.

A second limitation arises from the fact that only a part of the expenditure data is separately identified with oil or gas reservoirs. This necessitates reliance on discretionary allocation techniques which deprives the resulting cost estimates for the separate reservoirs of much of their economic significance as a measure of the cost of providing supplies. Thus, the cost estimates for total hydrocarbons are more significant than the cost estimates for the separate reservoirs. However, the former are more significant only in the sense of being more reliable for the purpose of computing the return or cost-revenue relationship; the cost estimates for total hydrocarbons also do not provide an accurate measure of the cost of new supplies because they reflect a conversion of gas into equivalent oil barrels. That conversion was made on a relative revenue basis, which reflects, of course, the use of discretionary judgment.

A third limitation arises from the absence of historical data on annual reserve additions for the Gulf of Mexico. Reserve figures are limited to end of year remaining reserves for 1966 and 1967 only, from which, in conjunction with production data, aggregate gross reserve additions for the period ending with 1967 can be computed. However, any computation of annual reserve additions of a recent period, which underlie the unit cost computations in this study, rests on statistical techniques of estimation.

A fourth limitation arises from the need to relate the reported (or estimated) reserve additions, both offshore and onshore, to dollar expenditures in order to arrive at a unit cost. That technique proceeds on the implicit assumption that the reserve additions reported as extensions and revisions are related to the discoveries of the same period, whereas in fact a portion of the extensions and revisions relate to prior years' discoveries. That assumption was dictated by the limitations of the data. Any alternative technique would have required arbitrary assumptions as to the lag between the making of expenditures and the reporting of reserve additions; nevertheless, the inability to relate expenditures to the reserve additions directly resulting from these expenditures is a limitation prevading any costing of hydrocarbons.

A fifth limitation arises from the attempt to identify exploratory expenditures with particular areas. The exploratory effort is national in scope; each area benefits from the knowledge gained in the course of exploratory activities conducted in other areas. An accurate measure of exploratory cost by selected areas is thus not possible.

A sixth limitation arises from the fact that the computed unit cost is significantly influenced by the level of drilling activity and therefore, even in the absence of all of the above limitations, may not furnish a reliable measure of the cost of providing future supplies. In general, the higher the level of drilling activity, the higher will be the cost of input factors. Moreover, the level of drilling activity has an influence on success ratios; the greater the activity, the greater the probability that marginal prospects will be explored. Thus, any unit cost computation related to past reserve additions reflects whatever happens to have been the level of drilling activity. Unit costs will be different if the level of activity is expanded or contracted in response to a change in price incentives.

CHAPTER B
THE PROFITABILITY OF FINDING AND PRODUCING HYDROCARBONS

There is no single approach to the measurement of profitability or return earned from the sale of hydrocarbons. Return may be expressed in terms of the profit margin in relation to revenues, in terms of a rate of profit on capital invested at a given point in time, in terms of the time period (payout) required to recoup the investment, or in terms of the rate of interest (or profits) which equates the present value of the future stream of revenues with capital outlays, taking into account both the timing of expenditures and the receipt of revenues. The latter technique is usually referred to as the discounted cash flow (DCF) method. It will be used as the principal measurement of return in this study.

The discounted cash flow method is the most accurate technique of measuring the true yield of an investment, partly because it takes into account both the time value of money and the timing in the receipt of revenues. Both factors have a significant impact on profitability when the revenue flow resulting from the investment is stretched over a long time period, as it is in the production of hydrocarbons. The DCF technique has the additional advantage of avoiding arbitrary distinctions between "capital" items (which are entitled to a return) as distinguished from "expensed" items (which are not considered to be entitled to a return). From an economic point of view, the accounting distinctions between "capital" and "expensed" items are not appropriate for the purpose of measuring return. To illustrate, the fact that an expenditure results in a dry hole does not render it less of a capital expenditure merely because it is expensed on the books of account, nor does the act of expensing provide for a faster recovery of the expenditure through revenues than if it had been capitalized.[1]

Although the DCF technique has become an increasingly accepted tool of financial analysis, particularly for comparative appraisals of drilling prospects, its use in the context of an industry-wide cost study requires some further explanation with respect to three aspects: the timing of expenditures, the treatment of income taxes, and the comparison of the resulting measurement of return with the more traditional measures of return on net investment or book capital.

I. The Timing of Expenditures and the Treatment of Income Taxes in a Discounted Cash Flow Study

In the usual format for a DCF analysis, the expenditures for the different cost items are placed in the year in which they are made, and then matched (or netted) against the revenues received both during the period in which expenditures are made and thereafter. Thus, a net cash flow is computed for each year, which is typically a negative amount in the early years and a positive amount in later years. The true yield return is computed by finding the rate which will equate the compounding of the negative net cash flows with the discounting of the positive cash flows.

For purposes of the present study, a somewhat different format will be used, although the change in format does not alter the arithmetic results. The attempt to compute an industry-wide current cost with its concomitant need to smooth out erratic annual variations in expenditures through a process of averaging makes it difficult, if not impossible, to pinpoint the precise year in which particular expenditures are made in relation to the flow of revenues. In lieu thereof, the timing of expenditures is expressed in terms of an average time period between the incurrence of the outlays and the commencement of the flow of revenues. That average period is here called the preproduction time lag, expressed in years. In measuring the return, each expenditure item which is subject to a "time lag" (namely, the finding costs as distinguished from the production costs) is compounded at an annual rate by whatever average time lag (number of years) has been found for the different cost components. The compounding rate applied is, of course, the same as the rate of return found to equate the compounded finding costs to the discounted value of the revenue stream.

In computing the return by the DCF technique, it is customary to take into account the impact of income taxes on the net cash flow. Expenditures that are expensed for income tax purposes are reduced by what is referred to as "tax savings". To illustrate, assume a producer is in the 52 percent federal income tax bracket, and has spent $1 million for productive wells, of which 70 percent are intangible drilling costs, which are expensed for income tax purposes. The $1-million outlay is treated as the equivalent of a capital investment of $636,000, i.e., the $1-million outlay is reduced by the $364,000 of income taxes

[1] Unless regulation sets prices on the basis of costs and the thus determined prices are higher than prices received in a competitive market.

(52 percent of $700,000) saved through making the expenditure. Thus, "tax savings" arising in the early years of the project are treated as the equivalent of a "cash inflow", and the taxes which the receipt of revenues generates in the later years of the project are treated as "cash outflows". In general, the impact of the treatment of income taxes in such a DCF study is to show returns which are higher than if the impact (both cash inflows and outflows) had been disregarded.

The above treatment of "tax savings" is quite appropriate for the purpose of analyzing the relative profitability of competing projects, but is wholly inappropriate in the context of an industry-wide study, for two reasons. First, the treatment of "tax savings" as a cash inflow or reduction of investments assumes the availability of taxable income against which to offset tax deductions. The extent to which taxable income is available varies widely between different producing entitites; aggregate revenue and expenditure data do not provide an appropriate measure, so that it becomes impossible to know the industry's effective rate of "tax savings".

Second, the treatment of "tax savings" as an inflow of cash is a means of measuring the tax impact on profitability, thereby providing a more refined financial analysis of competing projects. But if the same technique were used in an industry-wide study, one would arrive at the absurd conclusion that the higher the tax rates, the higher will be the return, and vice versa, the lower the tax rates, the lower will be the return earned. Thus, if tax rates were raised to 100 percent, and all expenditures were immediately deductible for income tax purposes, the "net cash outlays" would be zero. The treatment of income tax savings as a cash inflow would thus result in a measure of return approaching infinity.

On an industry-wide basis, taxes would be a cash inflow only if the U.S. Treasury were to make payments to the industry. Industry-wide, income taxes are a cost; there are no "tax savings" in the sense of a reduction of investments. The effect of the income tax laws cannot go beyond complete elimination of income taxes as a component of cost; no "tax savings" can ever reduce the industry-wide cost of the product below the actual outlay. In this study, therefore, the impact of income taxes on return will be disregarded; concomitantly, no separate estimate will be made of the income tax liability incurred by the industry. Thus, the total computed cost will understate the industry's cost because of the omission of income taxes. However, the computed return will be lower than if the DCF technique had been applied in the customary manner for comparative analysis of projects and income taxes and been treated as a reduction of finding costs.

II. The Discounted Cash Flow Return of the Estimated Cost-Revenue Relationships

Four parameters determine the level of profitability measured by reference to a discounted cash flow return: the level of expenditures, the level of revenues, the timing of expenditures, and the timing of revenues, i.e., the rate of depletion (production) of the reservoirs.

The significance of taking into account the timing of expenditures and revenues in measuring profitability may be illustrated by first looking at the results of the estimated cost-revenue relationships for total hydrocarbons in the absence of considering the timing parameters. Such a measure of profitability is the return margin (revenues minus expenditures) in relation to gross revenues, shown in the following table:

Return Margin for Total Hydrocarbons[a/]

	Gulf of Mexico	Onshore So. La.	Other Continental U. S.
	(In Dollars per Barrel)		
1. Revenues, net of royalties	$2.82	$3.04	$2.57
2. Finding costs	1.19	1.17	1.07
3. Other costs	.59	.84	.77
4. Net revenues available for return [Lines 1 - (2+3)]	$1.04	$1.03	$ .73
5. Return margin (Lines 4 ÷ 1)	37%	34%	28%

a/ Non-associated gas converted to equivalent barrels of oil on a revenue basis.

Source: Statistical Appendix, Table 1.

The preceeding table suggests that the highest profitability is achieved in the Gulf of Mexico. But that conclusion is erroneous because it fails to take account of the relatively longer time that elapses in offshore operations between making the expenditure and the commencement of the receipt of revenues (see page 198). If the timing of revenues (see pages 201 and 227) and expenditures is taken into account, the operations in the Gulf of Mexico are more profitable than in the "Other United States", but less profitable than in onshore South Louisiana. The discounted cash flow returns, for total hydrocarbons as well as for oil and gas reservoirs separately, are shown in the following table:

	Discounted Cash Flow Return Indicated by Current Cost- Revenue Relationships		
	Oil Reser- voirs	Gas Reser- voirs	Total Hydro- carbons[a]
	(In percent)		
Gulf of Mexico[b]	5.0-5.4	5.7-6.6	5.6
Onshore South Louisiana	6.4	5.8	6.2
Other Continental U.S.	4.3	3.2	4.0

[a] Non-associated gas converted to equivalent barrels of oil on a revenue basis.
[b] For an explanation of the range, see page 176.

The above results suggest that oil reservoirs are more profitable than gas reservoirs in onshore operations, but less profitable in the Gulf of Mexico. However, the difference in the estimated levels of profitability as between oil and gas reservoirs may be the result of the unavoidable use of discretionary allocations.

III. Estimated Return on Capitalized Finding Costs

The discounted cash flow technique produces results that are not comparable with the usual return measurements computed from financial statements, such as earnings on net investment or on book capital at a particular point in time. With few exceptions, the DCF technique will show a lower measure of return than these alternative measures of profitability. It may therefore be of interest to convert the DCF results into an approximation of the level of return which would be indicated by reference to the more traditional measures of return on capital. It should be emphasized, however, that the comparison furnished below is, at best, a rough approximation.

The DCF results express the return in relation to total finding costs, comprising productive drilling and equipment costs, lease acquisitions, dry holes, geological, geophysical and other exploratory costs. The productive drilling and equipping costs are typically capitalized on the books and amortized during the life of the reservoirs. Lease acquisitions are also capitalized at the time of payment of the bonus; if production is obtained, the costs are amortized; if the leases are surrendered, the cost is written off. The remaining finding costs are typically written off when incurred, except that geophysical and geological costs which are identifiable with productive properties are capitalized. Thus, a precise determination of the proportion of finding costs which are capitalized cannot be readily made. For present purposes, it will be assumed that all productive drilling and equipping costs as well as lease acquisitions are capitalized (and are amortized on a unit of production basis), and that the remaining finding costs are treated as expenses on the books of account.

To treat finding costs as expenses implies (contrary to fact) that they are incurred and reimbursed out of revenues in the year in which the expenditures are made. Stated differently, the finding costs which are treated as expenses must be considered as annually recurring costs, analogous to operating costs which are incurred as the reservoirs are depleted. It will be recalled that in the instant study all finding costs are related to reserve additions. That technique of measurement implies that they are capital costs depleted over the life of the reservoir. If a portion of finding costs are now considered as items expensed on the books, then these expenditures must be related to units of production; i.e., the unit cost

must be converted from a reserves added basis to a unit of production basis. That conversion will be made by multiplying the unit finding costs by the ratio of reserve additions to production.[1] After making this adjustment, the cost-revenue relation and the indicated return on capitalized finding costs is:

Approximate Average Return on Capitalized Finding Costs for Total Hydrocarbons[a/]

	Gulf of Mexico	Onshore So. La.	Other Continental U. S.
	(In dollars per barrel)		
1. Revenues, net of royalties	$2.82	$3.04	$2.57
2. Depletion, depreciation & amortization of capitalized finding costs[b/]	.80	.69	.68
3. Expensed finding costs[c/]	.62	.43	.35
4. Other costs	.59	.84	.77
5. Net revenues available for return [Lines 1 - (2+3+4)]	$ .81	$1.08	$ .77
6. Average return on capitalized finding costs over the life of the reservoirs	8.2%	11.5%	6.9%

a/ Non-associated gas converted to equivalent barrels of oil on a revenue basis.

b/ Reflects sum of productive drilling, lease facilities, and lease acquisitions.

c/ Reflects conversion of dry hole, geophysical, geological and other exploratory costs from a reserves added to a unit of production basis. The conversion is made on the basis of finding to production ratios 1.6 for Gulf of Mexico and 0.9 for onshore operations.

Source: Derived from Tables on pages 206, 207, 208, and 227.

by reference to traditional financial statements which, in the case of oil companies, do not reflect any capitalization of interest during construction. However, the computed rates of return in the above table do reflect the timing of the receipt of revenues, i.e., they take into consideration the depletion

The above returns on capitalized finding costs totally disregard the timing of expenditures, i.e., they reflect no compounding of interest for the preproduction period. The purpose here is to achieve a rough comparison with return measurements made (production) pattern of the reservoirs. The rates of return shown reflect the average[2] return earned during the life of the reservoirs.

The above table shows solely the estimated return on capitalized finding costs for total hydrocarbons. Comparable separate estimates for oil and gas reservoirs are shown on the following page.

[1] While the concept is simple, its quantification is fraught with many uncertainties. The objective is to approximate the industry's future dry hole, geophysical, geological, and other exploratory expenditures on a unit of production basis. Assuming no increase in real costs, the unit cost will depend on the relation between findings and production which will, of course, vary from year to year. For purposes of this study, the findings to production ratios were derived from the projections made in Part I for the period 1968-1985. For onshore areas, the average findings to production ratios were computed at 0.9 for both oil and gas; for the Gulf of Mexico the ratios were 1.4 for oil, 1.8 for gas, and 1.6 for total hydrocarbons.

[2] The average return earned is computed with the aid of discount tables. In the early period of depletion of the reservoirs, the annual return on capitalized findings costs is less than in the later period of depletion, because the outstanding unamortized investment is high in the early period and declines as the reservoirs are depleted. A simple average of the annual returns on capital would not accurately reflect the profitability, because the value of deferred income is less than the value of present income. Only through use of discount tables can the profitability (taking into account the time value of money) be accurately computed.

	Approximate Average Return on Capitalized Finding Costs	
	Oil Reservoirs	Gas Reservoirs
	-------(In percent)---------	
Gulf of Mexico[a/]	7.2 - 8.0	8.3 - 10.4
Onshore So. Louisiana	11.9	11.0
Other Continental U.S.	7.2	5.9

[a/] For an explanation of the range see page 176.

The above results confirm the previously expressed conclusions that the profitability of operations in the Gulf of Mexico is higher than in Other Continental U.S., but lower than onshore South Louisiana.

Although the computed returns on capitalized finding costs reflect only rough approximations, they indicate the overall profitability of current outlays for finding and producing hydrocarbons is less than the returns on capital experienced by the domestic oil industry in its exploration and production activities in earlier years. Financial data for a group of small and medium-sized companies primarily engaged in exploration and production operations show their average return on total capital at 14 percent (after income taxes) for the period 1961-1965.[1] The integrated producers do not publish financial data separately for their production as distinct from their refining or integrated operations. However, data collected in connection with proceedings before the Federal Power Commission showed that, in 1960 and 1962, the return earned (before income taxes) by 20 large integrated companies was about 13 percent on net investments in domestic production and exploration operations.[1] The above estimates of return on capitalized costs, which are before income taxes, therefore indicate that the industry is experiencing a decline in profitability on its current expenditures.

[1] FPC Docket Nos. AR64-1 and AR64-2; Exh. 121-J.

CHAPTER C
TECHNIQUES OF ESTIMATING INDIVIDUAL COST AND REVENUE COMPONENTS

This chapter contains a more detailed description of the techniques used in estimating each of the individual cost and revenue components. A logical starting point is the estimation of reserve additions.

I. Alternative Measures of Reserve Additions

Throughout this study reliance was placed on the reserve data reported by the AGA-API. These data are available in two forms. First, data on gross annual reserve additions (oil, gas, and natural gas liquids) are reported separately for (1) discoveries, and (2) extensions and revisions. The extensions and revisions reflect the knowledge gained through developmental drilling and production experience of discoveries in earlier years, but are attributed to the year in which the reserve additions (or deductions) become known; they are not attributed to the year in which the discoveries were made. These are the data which in this study are related to expenditure estimates.

A second set of data published by the AGA-API shows "ultimate recoverable reserves". Here the extensions and revisions are attributed back to the year of discovery. It would have been preferable to rely on these data for the estimate of unit costs if they reflected truly "ultimate recoverable reserves". However, the extensions and revisions which are attributed back to the year of discovery reflect only those reserve additions which are presently known as the result of development drilling and production experience. Thus, the reported reserve additions in the most recent period understate the results of the finding effort, since they reflect predominantly only "discoveries". If the purpose of this study were to ascertain the cost of reserves found for a period ending a decade ago, the data on "ultimate recoverable reserves" would have constituted a superior source to the annual reported reserve additions. However, since the purpose is to estimate the finding and developing cost per unit of reserve additions for the most recent period possible, which may have some validity for the near-term future, the understatement of the "ultimate recoverable reserves" for the most recent period led to a rejection of this measure of reserve additions.

Reliance on the annually reported reserve additions does not, of course, furnish an accurate reflection of the recent exploratory and development effort. These data merely avoid an understatement by adding to current discoveries the extensions and revisions which are related to earlier discoveries. In relying on reported reserve additions, one proceeds on the assumption that the relation between the discoveries and the sum of extensions and revisions will be the same in the future as it has been in the past. Since that assumption cannot be tested by empirical facts, any measure of reserve additions for a recent period must be tested by reference to longer time periods stretching into the more distant past.

II. Techniques of Estimating Reserve Additions

The AGA-API reserve reports readily permit the computations of annual reserve additions for crude oil, natural gas and natural gas liquids, by state, by Railroad Districts within Texas, and separately for North and South Louisiana. However, data on offshore reserves are reported only for year-end remaining reserves in the Gulf of Mexico for 1966 and 1967. It was therefore necessary to estimate the annual reserve additions for the Gulf of Mexico. Since over 95 percent of the Gulf of Mexico reserves are in the offshore Louisiana Gulf area, the estimate of offshore annual reserve additions was, in essence, accomplished by splitting the reported annual reserve additions for South Louisiana between on- and offshore.

Reserve additions of natural gas and natural gas liquids are not useful for costing purposes, without a further division between non-associated and associated gas, because the latter are a component of oil reservoirs. Until 1966, the AGA reserve reports set forth data only on remaining year-end reserves for non-associated and associated gas (and gas liquids) without a similar breakdown for production volumes and reserve additions. However, gross annual reserve additions of non-associated gas can be computed using estimates of production from non-associated as distinguished from associated gas reservoirs.[1] Any uncertainties created by the need to estimate respective production volumes are dwarfed by the need to split the reserve additions for South Louisiana between onshore and offshore reserves.

The offshore gross reserve addition estimates utilized in this study reflect the following techniques

[1] Based on data derived from the Bureau of Mines and the Louisiana Geological Survey.

of splitting offshore from total South Louisiana data.[1]

For *crude oil*, South Louisiana annual gross reserve additions were distributed between onshore and offshore in proportion to the annual *increments* of production. This technique makes two implicit assumptions: first, that the time between the discovery of oil reservoirs and the commencement of production is the same offshore as onshore, although the available evidence suggests that it is longer offshore, since the construction of offshore oil pipelines is accompanied by significant delays, and transportation by barges is not a perfect substitute for pipelines; second, it assumes that there has been no change in relative rates of depletion of the reservoirs offshore compared to onshore. In fact, however, offshore allowables have increased during the last 15 years relative to onshore allowables. The errors introduced by these assumptions tend to be offsetting; nevertheless, the results indicate that the selected technique of distributing reserves appears to result in an overestimate of reserve additions by approximately 10 percent. The results were tested by comparing the sum of the computed annual reserve additions with the cumulative reported reserve additions reflecting year-end 1966 remaining reserves plus cumulative production. The above-described technique of estimating annual reserve additions results in cumulative offshore reserve additions in the period 1949-1966 of 3,786 MM barrels; the sum of remaining year-end reserves plus cumulative production shows cumulative reserve additions at 3,445 MM barrels. A proportional downward adjustment was therefore made to the computed annual reserve estimates to bring about a balance with the 3,445 MM barrels. The resulting annual additions are shown on page 209.[2]

[1] These techniques were selected after experimentation with a number of alternatives. In selecting a preferred technique, primary emphasis was placed on the degree to which the results were confirmed by the available data on remaining reserves, i.e., the sum of the computed annual reserve additions for offshore was compared with the AGA-API reported remaining reserves as of 1966 augmented by cumulative production.

In making that comparison, the reserves applicable to the offshore Texas Gulf Coast were split out from the total remaining reserves in proportion to cumulative production. By this technique, the following percentages of Gulf of Mexico offshore reserves, as per end of 1966, were attributed to the Texas Gulf Coast:

Crude oil:	0.3 percent
Non-associated gas:	4.0 percent
Associated gas:	0.4 percent

[2] The estimates for onshore South Louisiana reserve additions reflect the difference between total South Louisiana and the computed estimates for offshore South Louisiana.

In summary, the starting point for the computation of annual reserve additions is the gross additions of reserves for combined offshore and onshore South Louisiana which are the sum of net changes in year-end reserves plus annual production. The gross additions are then split between offshore and onshore in proportion to annual increments of production.

The split of gross reserve additions of *non-associated natural gas* between onshore and offshore South Louisiana was also made in proportion to annual increments of production; however, the increments of production were lagged 3 years for offshore and 1 year for onshore. To illustrate, the 1957 increment in offshore production was used to estimate the reserve additions for 1954 and the 1957 onshore increment was used to estimate the reserve additions for 1956. The reason for the use of lags is the time span between drilling—which prompts the reporting of reserve additions—and the construction of pipelines to transport the gas, for which the delay is significantly longer offshore than onshore.

The employment of 3-year lag periods made it impossible to use the techniques of increments of production for the last three years. The 1967 gross reserve additions were computed from the increase in reserves between 1966 and 1967 plus 1967 production. For 1965 and 1966, the gross reserve additions for total South Louisiana were split in proportion to the number of discoveries. Using this technique of distribution, the cumulative gross reserve additions through 1966 were computed at 29,054 billion cubic feet as compared to the reported gross reserve additions (year-end reserves plus cumulative production) of 30,584 billion cubic feet.[3] The annual gross reserve additions shown on Table 5 reflect a proportional adjustment to balance the computed estimates with the total derived from AGA data.

Associated gas reserves are discovered in connection with the search for crude oil. Offshore South Louisiana reserve additions were therefore estimated on the basis of the gas : oil ratio, which was 1.373 Mcf per barrel for the period ending 1966. The annual offshore associated reserve additions were computed by assuming that the cumulative ratio of 1.373 Mcf per barrel was applicable each year throughout the period, i.e., the previously computed

[3] This figure reflects reported remaining year-end 1966 Gulf of Mexico offshore reserves, reduced by 4 percent for an estimate of Texas Gulf Coast offshore reserves (see footnote on page 194).

annual reserve additions of oil were multiplied by 1.373 to obtain an estimate of associated offshore reserve additions.[1] In view of the techniques used, no significance is attached to the annual reserve additions, which are set forth on page 209 only to provide an indication of the relative magnitude of associated reserve additions. In this study the associated reserve additions are not costed separately from crude oil reserves; such costing would have to rely on wholly arbitrary allocation techniques which are of no economic significance. The data on associated reserve additions are used for the sole purpose of computing the revenue stream of oil reservoirs.

Attempts were also made to estimate annual reserve additions for *natural gas liquids*, separately for non-associated and associated gas, again for the purpose of computing the revenue stream from the respective reservoirs. However, the data limitations present virtually insuperable obstacles. Non-associated natural gas liquids comprise both lease condensate and liquids extracted in processing, but the AGA reserve data do not distinguish between the two. Moreover, the reporting of plant liquid reserve additions is dependent on the availability of recovery facilities as well as their efficiency of extraction. Thus, the reported reserve additions in recent years are only partly the result of new discoveries; they also reflect—in an unknown degree—the installation of new recovery facilities and the improvement in the techniques of liquid extraction. These limitations—which are applicable to national as well as South Louisiana data—make it impossible to compute annual reserve additions which have even a semblance of reliability. However, natural gas liquids play a significant role in total reserve additions, so that it is desirable to obtain some approximation of the quantities of natural gas liquid reserves which are added along with natural gas reserves.

As shown on page 210, the end of 1967 remaining reserves of non-associated natural gas liquids in South Louisiana (on- and offshore) amount to 31.4 barrels per MMcf for the remainder of the U.S. In contrast, the reserves of associated gas liquids in South Louisiana are only 24.8 barrels per MMcf as compared to 50.2 barrels per MMcf for the remainder of the U.S. Focusing on the South Louisiana figure of 31.4 barrels per MMcf of non-associated gas, the AGA data also shows that offshore non-associated gas reserves have a significantly lower liquid content than on-shore. For offshore, the year-end 1967 liquid: gas ratio is 24.2 barrels per MMcf as compared to 36.7 barrels per MMcf for onshore.[2]

A further benchmark can be obtained by reference to *cumulative* reserve additions. The liquid : gas ratio for non-associated gas was 29.4 barrels per MMcf for total South Louisiana, 20.0 for offshore and 33.9 for onshore. Clearly, the offshore natural gas reserve additions are leaner than onshore reserve additions, although the available data may overstate the leanness due to the relatively small number of plants presently available for the processing of offshore gas.

The inability to estimate natural gas liquids reserve additions is not a serious obstacle to the objective of this study, since no separate costing of natural gas liquids is attempted. Natural gas liquids are found in either crude oil or non-associated gas reservoirs; a separate costing of natural gas liquids would have to rely on wholly arbitrary allocation methods. The inquiry with respect to the magnitude of the reserve additions of natural gas liquids is for the purpose of estimating the revenue stream of oil and non-associated gas reservoirs. In the absence of reliable data on reserve additions, the estimate of the revenue stream will be made by reference to production volumes (see Section 12 below) [3]

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[1] Onshore reserve additions of associated gas reflect the difference between total South Louisiana and the computed estimates for offshore South Louisiana.

[2] The comparable figures for the year-end 1967 associated gas reserves are 18.4 barrels per MMcf for offshore and 27.3 barrels per MMcf for onshore.

[3] Despite the obstacles to the estimation of natural gas liquid reserve additions, several attempts were nevertheless made to distribute South Louisiana reserve additions between offshore and onshore, to determine the existence of a potential trend in liquid yield. The results of three alternative techniques are shown on page 211. In the first approach, the indicated reserve additions were first computed for total South Louisiana, and then it was assumed that the offshore liquid: gas ratio remained at 20.0 barrels per MMcf throughout the period. The onshore reserve additions reflect the difference between total and offshore additions. Under that assumption, there is no clear trend in liquid yield of onshore reserve additions. In the second approach, it was assumed that the onshore reserve additions remained constant at 33.9 barrels per MMcf throughout the period; the offshore reserve additions were then computed by the difference between total South Louisiana and onshore. The results show significant negative reserve additions, an obvious absurdity. Finally, computed on the basis of increments of production, with differential lags for offshore and onshore, similar to the technique used for the distribution of non-associated gas reserves. The latter technique has relatively greater merit than the preceding techniques; however, the results show no clear trend in liquid yield of reserve additions, either offshore or onshore.

III. Reserves Added Per Productive Well or Foot Drilled

The fulcrum of any estimate of the cost of finding hydrocarbons is a measurement of the relation between the drilling effort and the reserves obtained. Although drilling encompasses both successful (productive) wells and dry holes, the latter are in the nature of joint costs not separately identifiable with either gas or oil reservoirs. Thus, initially the reserve additions will be related only to productive wells (or footage) for the reason that it is thus possible to obtain separate measurements for predominantly oil versus predominantly gas reservoirs. Dry holes will later be separately costed.

In relating reserve additions to the drilling effort (wells or footage drilled), the measurement of reserves is limited solely to crude oil and non-associated gas reserve additions. For this purpose the associated gas reserves, as well as natural gas liquids, are disregarded, to avoid the necessity of introducing discretionary judgments in converting those products in terms of barrel or Mcf equivalents. The omission of these products from the computation of reserves added per foot or well drilled does not mean that they are by-products; nor will the omission in any way affect the end result sought, namely, the measurement of profitability in the different geographic areas under consideration. To avoid distortion of the results, the *total* revenues from *all* products found with a barrel of oil will be related only to barrels of crude oil and total revenues from all products found with an Mcf of gas will be related only to nonassociated gas.

The drilling activity, in terms of both number of wells and footage, is shown on pages 212-214, for offshore Louisiana, onshore Louisiana, and for Continental United States, excluding South Louisiana. The data are shown from 1954, the earliest date for which reliable data are available for offshore operations.

The results of relating the estimated annual reserve additions to the number of productive wells and footage drilled are shown on pages 215 and 216. Since these tables are one of the significant results of this study, a summary is shown below.

RESERVE ADDITIONS PER FOOT DRILLED

The data below indicate that the oil reserves added per foot drilled are approximately twice as high offshore as onshore Louisiana, and approximately two and one-half times as high offshore as for the Continental United States, outside of South Louisiana. For non-associated gas, the reserve additions are approximately 2.3 times as high offshore as compared to onshore Louisiana, and five times as high offshore as compared to Continental United States, outside of South Louisiana.

Turning to the meaning and significance of these data, two questions arise: Is there a trend in reserves added per foot drilled, and do the data furnish an indication of prospective levels? Except for an upward trend in oil reserve additions for Continental U.S. excluding South Louisiana, an examination of pages 215 and 216 shows an extremely erratic pattern of annual reserve additions per well or foot drilled. Any measurement of the levels of reserve additions per foot drilled must therefore be based on relatively long time periods.

RESERVE ADDITIONS PER FOOT DRILLED

	Crude Oil (Barrels)			Non-Associated Gas (Thousands of Cubic Feet)		
	Offshore La.	Onshore So. La.	Other U. S.	Offshore La.	Onshore So. La.	Other U. S.
1954-67	84	42	28	2,364	937	448
1958-67	81	44	30	2,366	941	446
1961-67	82	39	31	2,327	1,063	454
1963-67	79	41	34	2,318	1,002	500

Source: Table, page 216.

In interpreting the data, it should be recalled that the measurement of reserve additions reflects the implicit assumption that extensions and revisions are related to the discoveries in the years in which they are reported, whereas in fact they are the result of prior discoveries. Moreover, the apparent increase in oil reserve additions per foot drilled in the United States outside of South Louisiana is partly the result of upward revisions of oil reserves due to secondary recovery operations. A further limitation of the data arises from the fact that the level of reserve additions per foot is influenced by the intensity of drilling activity; the observation is particularly germane for the interpretation of the data for onshore South Louisiana and Other Continental U.S. As drilling, particularly exploratory drilling, declines, the search becomes more selective, so that in the short run there appears to be an increase in reserves added per foot drilled. In South Louisiana, total drilling declined by approximately 25 percent in the last 10 years; in Other Continental U.S., the decline was 40 percent. The apparent increase in reserves added per foot may therefore be deceptive as an indication of trend or measure of future performance.

Focusing on offshore, the most significant figure is the average for the period 1954-1967, rather than the data for the more recent periods. The latter may be influenced by the statistical techniques used in distributing onshore and offshore reserve additions, whereas the 1954-1967 average is virtually free of that influence and reflects the cumulative offshore reserve additions per foot drilled. However, all the data are subject to a limitation, not applicable in the same degree to the other areas, arising from the relatively large number of wells that are completed in both gas and oil zones. In such circumstances, the wells are reported as either gas or oil wells, depending on whichever product is predominant in terms of value. In most cases, they are reported as oil wells, so that the published data tend to produce an overstatement of the footage attributable to oil and an understatement of gas footage. The degree of the respective errors is unknown, but the data on reserve additions per foot drilled are highly sensitive to small errors, particularly for gas. To illustrate, if the practice of classifying dual-zone completions by major product value resulted in a 5 percent overstatement of oil footage in the period 1963-1967, a correction would change the reserves added per foot from 80 barrels to 84 barrels for oil wells. The corresponding impact on gas would result in a change from 2,320 Mcf to 2,020 Mcf, a decline of 13 percent. In view of this uncertainty, the reserves added per foot drilled will be expressed in terms of a range.

The computed data on reserve additions per foot for offshore indicate a slightly declining trend. In view of the sensitivity of the results, particularly for gas, to corrections for the failure to apportion dual-zone completions between oil and gas, there can be no assurance that the computed data will reflect the prospective drilling experience. Moreover, the annual reported reserve additions include extensions and revisions of discoveries of earlier periods made primarily in shallower water depths, compared to the water depths in which the bulk of the present or prospective drilling will take place. There is some evidence that drilling in Zone 4 will show lesser reserve additions per foot drilled than the nearer Zones 1-3. The reserve data for major fields published by the *Oil and Gas Journal*[1] suggest that the reserve additions per well were approximately 10 percent lower in Zone 4 than in the other zones. Reserve data by zones provided by the Interior Department[2] suggest that the reserve additions per well as of 1965 were substantially lower (65 percent) than in other zones. Of course, these rough approximations must be discounted for the fact that Zone 4 is at a lesser development stage than other zones. Nevertheless, these indications suggest that the selection of the lower range of the figures on reserves added per foot provides a better indication of current and prospective experience than the slightly higher earlier figures.

The figures used in the cost estimates are reflected on the following page.

These figures are very close to the 1963-1967 average experience; they are probably an overstatement of prospective experience for the reasons that, with respect to offshore, the deeper water drilling in Zone 4 may prove to be less rewarding than the nearer zones. With respect to onshore operations, the selected figures disregard the fact that the higher reserve additions in recent years may be a reflection of the greater selectivity of drilling accompanying the cut-back in drilling activity.

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1 *Oil and Gas Journal*, January 30, 1967, and February 5, 1968.

2 U.S. Department of the Interior, *Petroleum Production, Drilling and Leasing on the Outer Continental Shelf*, May 1966, p. 51. Both this publication and *Oil and Gas Journal* (1/30/67 and 2/5/68) show reserve information only in barrels, without indication whether they have omitted gas findings or whether the latter have been converted into equivalent barrels.

	Reserves Added Per Foot Drilled		
	Crude Oil (Bbl.)	Non-Associated Gas (Mcf)	Total Hydrocarbons[a]
Offshore Louisiana	80-84	2,020-2,320	102
Onshore South Louisiana	40	1,000	53
United States, excluding South Louisiana	32	490	33

a/ Non-associated gas converted to equivalent barrels of crude oil on a revenue basis. (See page 196).

IV. Drilling Costs

a. Drilling costs per barrel or Mcf of reserves found

Expenditures made in the drilling of productive oil or gas wells constitute by far the most important single cost component, accounting for over 40 percent of total finding costs. Time series on the costs per foot of drilling are shown on page 217, as reported by the Joint Association Survey.[1] The data are industry-wide averages and therefore reflect all of the determinants of drilling cost, such as depth of well or water, shifts between exploratory and development drilling, the magnitude of the drilling effort, and the countervailing forces of inflation and technological improvements. These averages are nevertheless useful indicators of cost for the purpose of computing the drilling cost per barrel or per Mcf found, measured by dividing the reserve additions per foot into the cost per foot drilled.

During the last few years, the offshore Louisiana cost per foot of oil wells has been approximately twice as high as the onshore South Louisiana cost, and the latter has been about 60 percent higher than in the United States outside South Louisiana.[2] For gas wells, the offshore cost has been approximately 65 percent higher than onshore cost, and the latter about 85 percent higher than for the remaining United States.

On a national, industry-wide basis, drilling costs have generally been rising during the post-World War II period; they reached a peak around 1957-1958, declined slightly during the next five years, and have been steadily rising since 1963. The rise in cost until the late 1950's was due both to inflation and progressively greater depths, mitigated by the improvements in technology; the slight decline in the late 1950's and early 1960's appears to have been due to a slackening of inflationary pressures, a general decline in drilling activity, coupled with continued improvements in technology. The rise in recent years is due largely to the renewed impact of inflation. The persistent inflationary pressures make it improbable that the most recent available data (1966) will furnish a reliable indicator for current or prospective cost. As shown in the next table, drilling cost rose by approximately 10 percent for gas wells and 5 percent for oil wells between 1965 and 1966.

In view of the further experienced inflation, it is estimated that there was a further 3 percent rise in the cost per foot between 1966 and 1967.[3] If the above estimated 1967 cost per foot is related to the previously estimated reserve additions per foot drilled, the cost of drilling per barrel and per Mcf is found on the second chart of the next page.

[1] The reliability of Joint Association Survey has been challenged on the grounds that it is based on a non-random sample and tends to overstate industry-wide costs. (See FPC Opinion 468, page 51.) An independent determination of industry-wide drilling costs (for gas wells and dry holes) made by Foster Associates, Inc., by means of questionnaires for the period 1961-1965 failed to provide any substantiation of the alleged overstatement of costs.

[2] Consistent with the measurement of reserve additions per foot, the focus is again on offshore Louisiana rather than on the Gulf of Mexico. The drilling cost per foot offshore Texas is very close to the offshore Louisiana. However, the drilling cost offshore Alaska is about three times as high as offshore Gulf Coast.

[3] The reports of the Bureau of Labor Statistics show that between December 1966 and December 1967, wholesale prices for oil field machinery and tools rose by 1.9 percent, wellhead assembly by 7.3 percent, oil well casing (carbon) by 4.1 percent and oil well casing (alloy) by 2.3 percent. The report of the Cost Study Committee of the Independent Petroleum Association of America, May 7, 1968, shows a rise of 3.4 percent in drilling and equipping cost per foot.

Cost Per Foot of Drilling

	Offshore Louisiana		Onshore So. La.		Other Continental U. S.	
	Oil Wells	Gas Wells	Oil Wells	Gas Wells	Oil Wells	Gas Wells
1965	$39.38	$51.58	$18.19	$28.30	$11.47	$15.48
1966	41.23	55.09	19.16	34.45	12.06	17.30
1967 (est.)	42.47	56.74	19.73	35.48	12.42	17.82

Source: Table 13.

	Oil Reservoirs (¢/bbl.)	Gas Reservoirs (¢/Mcf)	Total Hydrocarbons
Offshore Louisiana	51-53	2.45-2.81	45
Onshore So. Louisiana	49	3.55	47
United States, excluding So. La.	39	3.64	42

Source: Tables, pages 206, 207, and 208.

The above data show that for oil reservoirs the higher reserve additions per foot drilled offshore and onshore South Louisiana do not compensate for the higher cost of drilling, so that the lowest cost per barrel is experienced in the remaining Continental U.S. For gas reservoirs, however, the higher reserve additions per foot drilled in the Gulf of Mexico more than compensate for the higher drilling cost, so that the lowest cost per Mcf is experienced offshore.

b. Factors determining offshore drilling cost

Since future offshore drilling activity will probably be concentrated at greater water depths, longer distances from shore, and perhaps at greater well depths, it is important to obtain a measurement of the effect of these factors on drilling costs. In view of a virtual absence of published information (except for impact of well depth), the necessary data were obtained through the cooperation of a number of companies engaged in offshore drilling.

In analyzing the impact of water depth, well depth, and distance from shore, it is important to distinguish between drilling from mobile rigs and drilling from platforms.

(1) *Drilling from Mobile Rigs:* The preponderance of exploratory drilling is done from mobile rigs, which are self-contained units that can be moved from one drilling location to another. The mobile rigs are either submersible barge rigs, self-elevating platform rigs, ship-type rigs, or semi-submersible rigs.[1]

The cost of drilling with mobile rigs is shown in Chart I (see page 181), separately for dual completion, single completion and dry holes. These costs reflect only the cost of drilling the hole (the intangible cost), and do not include the cost of equipping the wells (the tangible cost). These costs vary as a function of both water depth and well depth. The cost curves shown in Chart I reflect the

[1] For a more detailed description, see Richard J. Howe, *Development of Offshore Drilling and Production Technology*, a paper presented at the ASME Underwater Technology Division Conference, Newport News, Virginia, May 1967.

following day rates:

50-ft. water depth (mobile rig):	$10,000/dav
125-ft. water depth (mobile rig):	$12,000/day
250-ft. water depth (mobile rig):	$14,500/day
300-ft. water depth (floating rig):	$14,000/day

(2) *Drilling from Platforms:* Development drilling in offshore fields has been conducted primarily from platforms, either self-contained or tendered platforms. The self-contained platforms are typically large enough to provide space for drilling support equipment and crew quarters, whereas the tendered platform, being smaller, has these facilities located on an auxiliary floating vessel. Between five and twelve wells can be drilled from tendered platforms, whereas self-contained platforms can accommodate up to 24 wells. The average number of wells drilled from platforms has been only about 11 for oil wells and 7 for gas wells. Directional drilling techniques enable the driller to reach reservoir locations more than one mile in horizontal distance from the platform.[1]

The cost of platforms is significantly influenced by the quantity of steel necessary to support drilling rigs and production equipment, in addition to withstanding the overturning force of hurricane waves. The costs are therefore largely a function of water depth, and vary to a much lesser extent with distance from shore. As shown in Chart 2 (see page 182), the costs of tendered platforms (for 8-12 wells) have been approximately $1 million at 100 feet of water depth, and $2 million at 300 feet of water. They are projected to about $3 million at 400 feet of water. At greater water depths, it is doubtful that the high cost will make it economical to use tendered platforms supporting a maximum of 12 wells.

The cost of the large self-contained platforms (14-24 wells) rises at even steeper rates as water depth increases. The experienced costs range from approximately $1.5 million at 100 feet of water to about $3.7 million at 340 feet, the deepest-known platform to date. Engineering estimates project platform costs at 600 feet of water depth above $7 million.

Once a platform has been constructed, water depth is no longer a significant factor in drilling cost,[2] well depth and distance from operating base are the two important variables. The impact of well depth on drilling cost from self-contained platforms is shown in Chart 3 (see page 183), separately for dual completions, single completions, and dry holes. The impact of distance from shore is approximate as follows: at 6000-ft. depth, the cost of a well increases by approximately $20,000 for every 50 miles from the base of operations. At 12,000 feet, the well cost increases by approximately $35,000 every 50 miles from base.

It is thus clear that, barring unforeseen technological improvements, the cost of drilling offshore wells will continue to rise as reservoirs are drilled in greater water depths.

V. Lease Facilities

The above-discussed drilling costs exclude expenditures for production facilities such as flow lines, oil tanks, separators, treaters, dehydrators, water knock-outs, pressure valves, metering facilities, and quarters buildings.

Expenditure data for lease facilities are publicly available only from the Joint Association Survey, on a national, industry-wide basis, without separation between areas or between oil and gas reservoirs. Additional data on offshore expenditures were collected from several producers in the course of this study. A second body of data is available from the files of the Federal Power Commission, reflecting cumulative gross investments in lease and well facilities, separately for oil and gas leases, both for Continental United States and South Louisiana. However, these data cover only a portion of the industry. To render the data useful for the purpose of estimating industry-wide costs, the reported investments must be expressed in relation to other investment data of the same group of companies; the most appropriate relation is the ratio of gross investments in lease facilities to gross investments in drilling. The technique of estimating lease facilities in relation to drilling costs will here be adopted.

The Joint Association Survey data show the following ratios of lease equipment to productive drilling expenditures:

1959-1961	26.6%
1962-1963	32.8%
1964-1965	38.3%

The sharply rising trend in the cost of lease facilities in relation to drilling costs is partly the result of the increasing number of offshore platforms included in the data. Since platforms were included in the above drilling cost estimates, an approximately 25 percent downward adjustment of the JAS data is indicated. The current national ratio of lease facilities to drilling cost is therefore about 28.5 percent.

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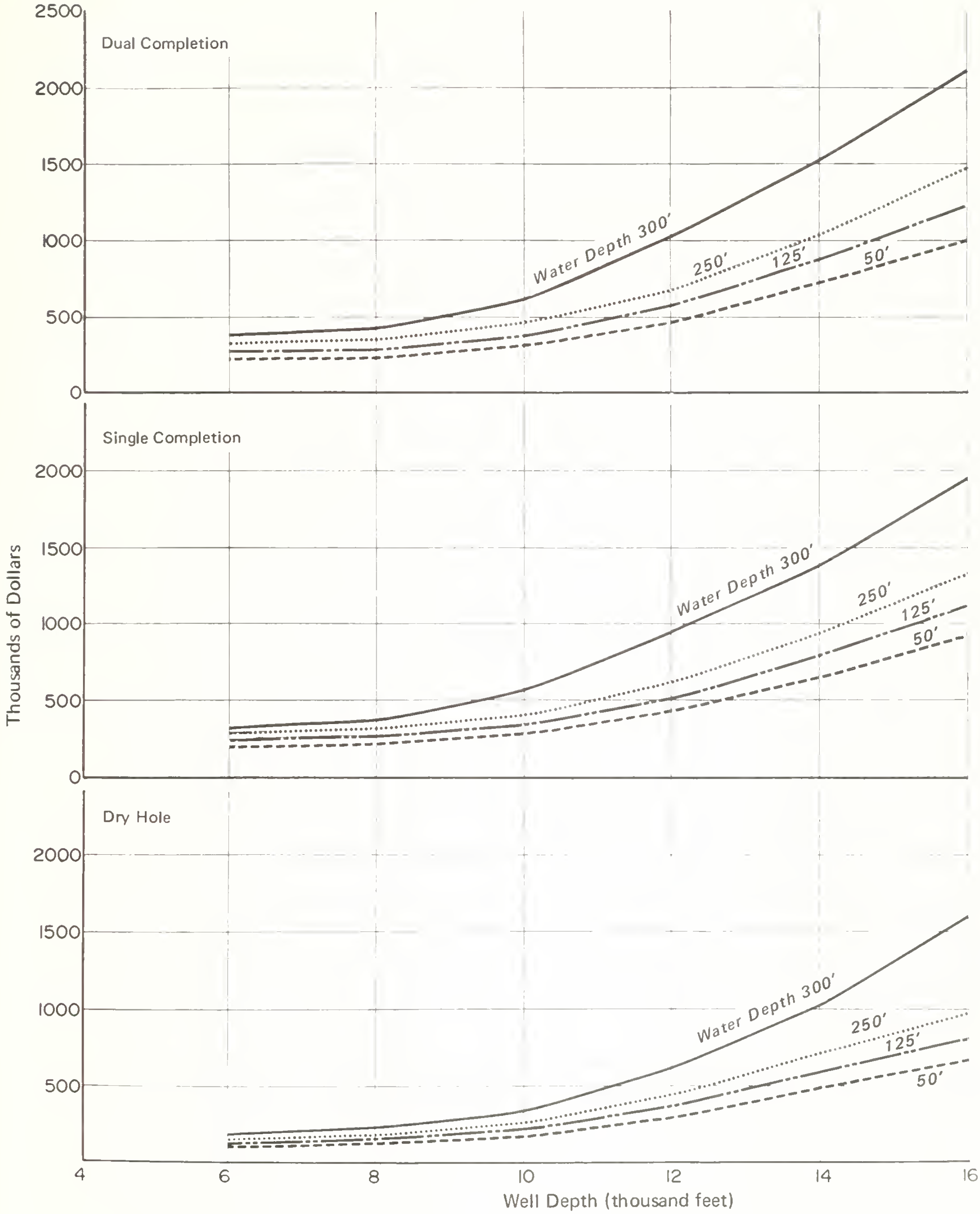
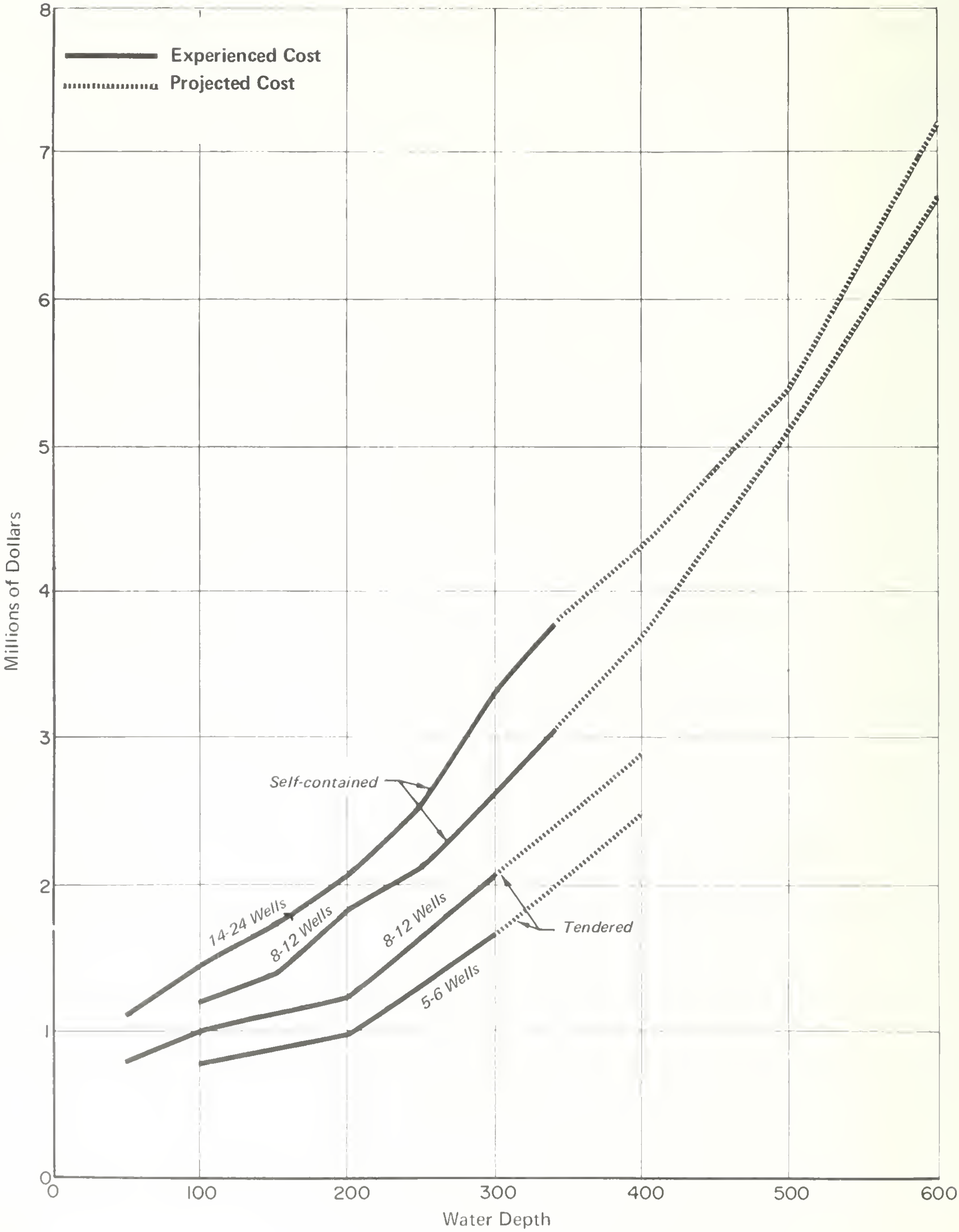
[1] For a description of the techniques of building platforms, see R. J. Howe, *op. cit.*

[2] At 200 feet of water, the additional cost per well is only $3,000: at 600 feet it is estimated at $11,000 per well.

OFFSHORE GULF COAST
DRILLING COST FOR MOBILE RIGS
IN RELATION TO
WATER DEPTH AND WELL DEPTH



PLATFORM COSTS IN RELATION TO WATER DEPTH

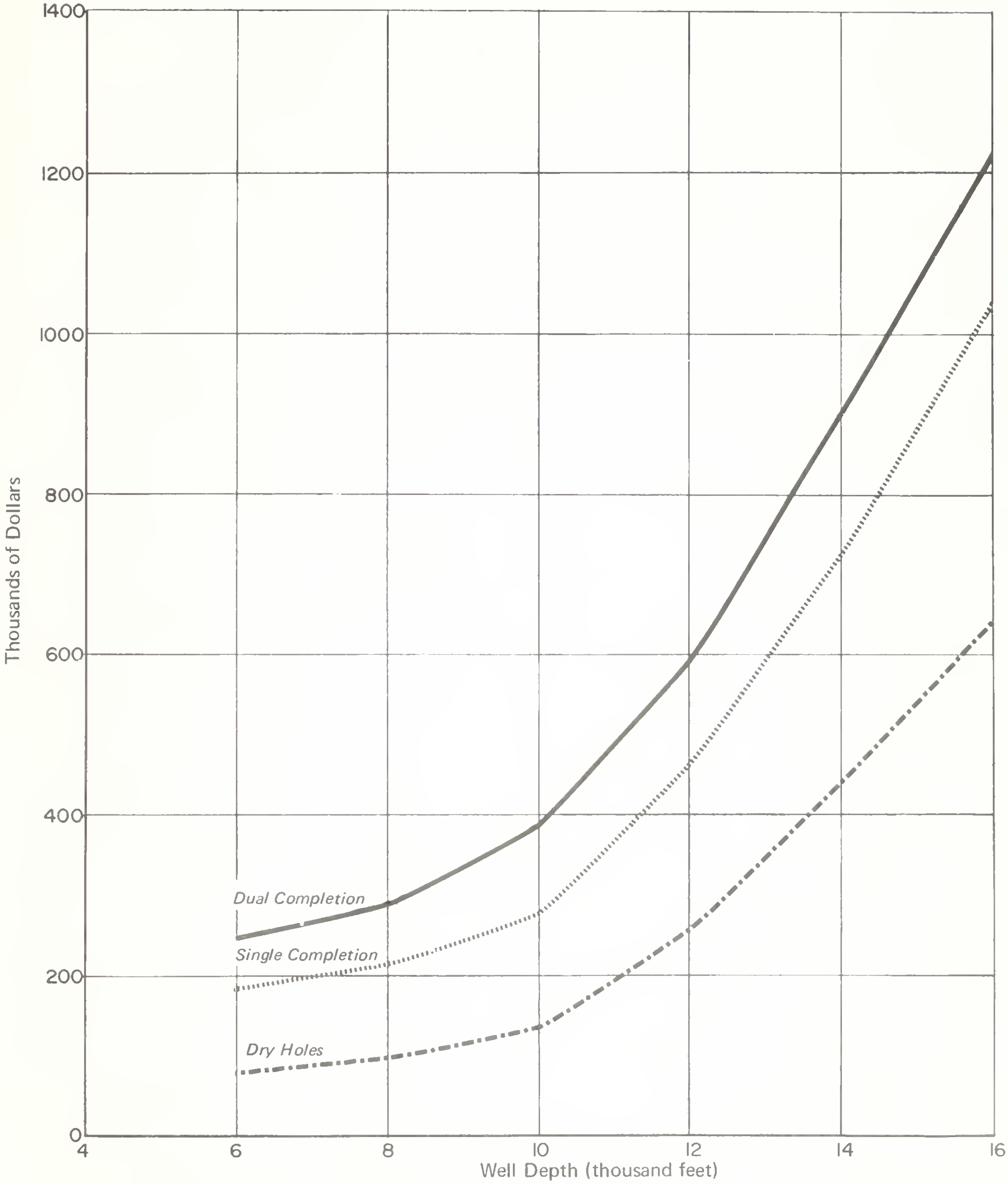


OFFSHORE GULF COAST

DRILLING AND EQUIPPING COST FOR WELLS DRILLED FROM SELF CONTAINED PLATFORMS

IN RELATION TO

WELL DEPTH



The FPC data on gross investments combine lease and well equipment. A technique of separately estimating lease equipment investment is developed on page 218. The analysis of these data shows that, at year-end 1962, the ratio of lease facilities to drilling investments was 22.2 percent, or within a narrow percentage of the 1959-1962 JAS expenditure data, after adjustment for the exclusion of platform costs. Thus, the closeness of the investment and expenditure data on a national basis suggests that the investment data for the separate areas, as well as for the separate oil and gas lease categories, will furnish reasonable cost approximations.

The investment data show that the ratio of lease facilities to well drilling investments is approximately one-third less in South Louisiana than in the remaining U.S. (page 218, line 9). Data collected in the course of this study show that the ratio of lease facilities to drilling costs is only slightly less for offshore than for onshore. The dollar expenditures for lease facilities per well (or lease) are actually greater offshore than onshore, and are greater in South Louisiana than in the remaining U.S. However, the ratio of lease facilities to drilling cost is lower offshore than onshore because the denominator (drilling cost) is relatively larger.

The FPC data also show that the ratio of lease facilities to well drilling investments is about 60 percent greater for oil than for gas leases in the Continental U.S., excluding South Louisiana. The typical oil lease not only requires more equipment than the gas lease but, since the drilling cost of gas wells is greater than of oil wells, the ratio of facilities to drilling cost is less for gas than for oil. However, the differential between oil and gas leases observed for the Continental United States is not present in offshore and onshore South Louisiana. Onshore, the high-pressure gas wells require relatively more costly equipment; offshore, the average number of gas wells per platform is about one-third less than the number of oil wells, so that the equipment in relation to total platform and drilling investment is about the same for oil as for gas wells.

As previously noted, the lease equipment in relation to drilling cost is currently approximately 28.5 percent for the United States; the 1962 investment data showed the ratio to be about 22 percent for total United States, 16 percent for South Louisiana, and 24 percent for Other United States. To utilize the investment data for the purpose of estimating current expenditures therefore requires an upward adjustment of about 30 percent; however, it would be inappropriate to apply a 30 percent adjustment to the ratio developed for the separate oil and gas lease categories without taking into account the relatively lower ratio of combination leases (see page 218). Taking both factors into consideration, as well as the relatively lesser ratios for offshore, the current ratios of lease facilities to drilling cost are estimated at:

	Ratio of Lease Facilities to Drilling Cost		
	Offshore Louisiana	Onshore So. La.	Other U. S.
Oil Reservoirs	19%	21%	35%
Gas Reservoirs	19	21	22
Total Hydrocarbons [a]	19	21	31

a/ Gas converted to equivalent barrels of oil on a revenue basis.

Multiplying the above percentages by the previously computed drilling cost per barrel and per Mcf results in the following estimates of lease facilities cost:

	Lease Facilities Cost		
	Offshore Louisiana	Onshore So. La.	Other U. S.
Oil Reservoirs (¢/bbl.)	10	10	14
Gas Reservoirs (¢/Mcf)	0.47 - 0.53	0.75	0.80
Total Hydrocarbons [a] (¢/bbl.)	8	10	13

a/ Gas converted to equivalent barrels of oil on a revenue basis.

Source: Tables, pages 206, 207, and 208.

VI. Dry Holes

a. Joint dry hole costs

Dry holes are an unavoidable cost of finding hydrocarbons. The incidence of dry holes (ratio of dry holes to productive wells) offshore has been steadily rising and has now reached a level that is somewhat higher than onshore Louisiana, which in turn is higher than for the remaining Continental United States.

	Ratio of Dry Holes to Productive Wells	
	1958-1962	1963-1967
Offshore Louisiana	0.48	0.93
Onshore South Louisiana	0.73	0.80
Other United States	0.63	0.70

Source: Page 219, Table 15, *World Oil.*

The present state of availability of data permits the computation of an economically meaningful cost of dry holes only for total hydrocarbons; any estimate of the cost of dry holes attributable to oil or gas reservoirs can be made only by means of arbitrary allocations.

The cost of dry holes can be readily computed by reference to dry hole footage multiplied by the cost per foot. In view of the rising trend in the incidence of dry holes, dry hole footage will be measured by reference to the 1963-1967 period, which was also given much weight in determining reserve additions per successful foot drilled.

The trend in the cost per foot of dry holes has been similar to the trend in the cost of productive wells, rising throughout the postwar period to reach a peak in the late 1950's, declining slightly in the ensuing years, and rising again since 1963. The JAS reported an approximately 7 percent rise in the cost per foot between 1965 and 1966 (page 217). It is estimated that a further 3 percent rise was experienced in 1967. The technique of computing the unit cost of dry holes is at the bottom of the page.

The table thus shows that the cost incurred for dry holes per barrel of reserves added is 15 percent lower offshore than onshore South Louisiana, but 9 percent higher than in the remaining U.S.

b. The allocation of dry holes to oil and gas reservoirs

In the allocation of dry hole costs, there is a wide gap between what is conceptually appropriate and what is practically feasible in view of the limitation of the data. Conceptually, a distinction should first be made between development dry holes and exploratory dry holes. The cost per foot of exploratory dry holes, nationally, is about 15 percent higher than the cost of development dry holes. Moreover, since development drilling is the exploitation of established gas or oil reservoirs,

	Offshore Louisiana	Onshore So. La.	Other U. S.
1. Estimated cost per foot (1967)	$38.04	$18.50	$9.82
2. Average annual dry hole footage (1963-1967) (000)	3,520	6,823	62,058
3. Total cost of dry holes (Lines 1 x 2) ($ 000)	133,901	126,226	609,410
4. Average annual reserves added (MMbbl. equivalent)	559.8	459.7	2,722.9
5. Cost per bbl. (Lines 3 ÷ 4)	24¢	28 ¢	22 ¢

Source: Page 217, line 1 - Table 13.
Pages 212, 213 and 214, line 2 - Tables 8, 9, and 10.
Page 209, line 4 - Derived from Table 5; gas converted to equivalent barrels of oil on a revenue basis.

developmental dry holes are in the nature of costs which are, at least conceptually, directly identifiable with gas or oil reservoirs. Data adduced at FPC hearings on a national industry-wide basis, show that the incidence of development dry holes is about twice as high for gas reservoirs as for oil reservoirs.[1] The data also show that the cost per foot of dry holes drilled in the development of gas reservoirs is approximately 25 percent greater than in oil reservoirs, principally because wells in gas reservoirs are drilled to greater depth than wells in oil reservoirs.[2] Thus, a separate computation of development dry holes attributable to the respective reservoirs is a prerequisite for an approximation of a measure of cost incurrence. However, data are not available for either onshore or offshore South Louisiana which would permit the ascertainment of development dry hole costs separately for oil and gas reservoirs.

With respect to exploratory dry holes, there is no conclusive evidence on the relative incidence of dry holes in the drilling of gas or oil reservoirs.[3] Thus, an allocation in proportion to either number of footage of successful exploratory gas and oil wells would be reasonable. However, as shown on page 220, the number of successful wildcat oil and gas wells is not only very small in relation to the number of dry holes, but also differs significantly between the two available sources, *World Oil* and *The Oil and Gas Journal*. The differences in reporting would have a very significant impact not only on the allocation of dry holes (see page 219), but the resulting allocated cost would also be highly sensitive to errors in the classification. To illustrate, for offshore Louisiana, *World Oil* reports for 1963-1967 a total of 14 successful wildcat oil wells, 19 gas wells and 791 dry holes. If the allocation were made in proportion to successful wells, 42 percent of dry holes would be allocated to oil; but if there had been a misclassification of a single well each year, the proportion allocated to oil would change to 58 percent. Thus, there are too few successful wells to furnish a reliable basis of allocation.

In the light of these limitations, the total dry hole costs will be allocated in proportion to the cost of drilling total productive (exploratory and development) oil and gas wells, for the period 1963-1967 (on page 221). Such an allocation tends to understate the cost appropriately attributable to gas reservoirs. It gives recognition to the fact that dry holes attributable to gas reservoirs are more costly than dry holes attributable to oil reservoirs; however, it tends to understate the cost of gas reservoirs by failing to give recognition to the fact that the incidence of development dry holes is significantly higher for gas than for oil and, because there has been an upward trend during the 1963-1967 period in the proportion of total costs accounted for by gas, this understatement is only partially offset by the slightly higher success ratios encountered at the greater depths to which gas wells are drilled. The technique of computing allocated unit cost is shown on the following page.

VII. Lease Acquisitions

Although accurate expenditure data are available for bonuses paid at federal offshore lease sales, and fairly reliable data are available on a nationwide basis, the measurement of the current cost of lease acquisitions per barrel presents difficult conceptual problems. Throughout this study, the emphasis has been placed on the measurement of current cost and the trend in cost; however, for lease acquisitions, the measurement must be shifted into the past, essentially for the reason that current bonus payments are made in the expectation of future reserve discoveries, the magnitude of which is unknown. Nor is it possible to compute a trend in offshore lease bonus payments on a dollar-per-acre basis, since the lease sales have been held at irregular intervals and have covered areas of widely varying size and degree of wildcatting. The irregularity of the intervals at which lease sales were held and the unavailability of data identifying reserve additions with particular leases makes it desirable to measure the cost of lease acquisitions over the longest possible period. Accordingly, the period selected is from 1954-1964, the beginning of federal offshore lease sales to the drainage sale related to the 1962 wildcat acreage sale.

A further difference in the approach to lease acquisition costs (as well as to geophysical and geological costs discussed below) is that the measurement of dollar expenditures will cover the entire Gulf of Mexico rather than offshore South Louisiana alone. In the economics of exploration, geographic boundaries are not meaningful; the knowledge gained offshore Louisiana is available in

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[1] See FPC Dockets AR64-1 and AR64-2, Exh. 89-J, Sch. 6.

[2] *Ibid.*, Exh. 12-J, Sch. 11.

[3] To the extent producers know whether they are drilling in an oil or gas structure, the cost of dry holes could be directly identified with either type of structure.

1963-67 avg.	Allocation of Dry Hole Costs: Offshore Louisiana: Oil Reservoirs	Offshore Louisiana: Gas Reservoirs	Onshore So. La.: Oil Reservoirs	Onshore So. La.: Gas Reservoirs	Other U. S.: Oil Reservoirs	Other U. S.: Gas Reservoirs
1. Total dry hole costs (million $)	133.9		126.2		609.4	
2. Proportion of oil & gas well drilling cost (%)	69.6	30.4	54.7	45.3	67.3	32.7
3. Dollar cost allocated (Lines 1 x 2) (million $)	93.2	40.7	69.0	57.2	410.1	199.3
4. Avg. annual reserve additions (MMbbl. or Bcf)	330.0	312.5	239.8	275.8	1998.0	10,359
5. Unit cost (¢/bbl. or Mcf) (Lines 3 ÷ 4)	28.2	1.30	28.8	2.07	20.5	1.92

Source: Paragraph 3, page 185, this report.
Page 221, line 2 - Table 17.
Page 209, line 4 - Table 5.

the exploration of offshore Texas, and vice versa.[1]

In the period 1954-1964, bonuses paid in federal offshore lease sales totalled $1,170 million. Since lease acqusition expenditures will be related to reserve additions seaward of the Chapman line, it is necessary to add expenditures for State of Louisiana offshore lease sales, which were estimated at 90 percent of total State lease sales, in submerged lands, amounting to $156 million. The aggregate 1954-1966 bonuses paid for offshore leases was therefore $1,326 million.

The Chase Manhattan Bank has estimated total U.S. lease acquisition expenditures in the period 1954-1964 at $6 billion[2] or, excluding the estimated offshore expenditures, at $4,674 million. Since no data are available separately for onshore Louisiana, this sum must be split between onshore Louisiana and the remaining U.S. An estimate of the lease bonuses paid onshore South Louisiana may be gained from the data collected by the FPC. These show, as of 1962, that the capitalized leaseholds (i.e., the leases on which productive wells were drilled) stood in approximately the same relation to capitalized well investments for South Louisiana as in the remaining U.S. As shown in Table 18, the ratio of leasehold to well investment was 20 percent for the remaining U.S. as compared to between 18-24 percent for South Louisiana.[3] Assuming these data to be an accurate reflection of leasehold costs, it would be reasonable to split the $4,674 million figure between onshore Louisiana and the remaining U.S. in proportion to drilling costs. Of course, these investment data do not furnish an accurate estimate of total leasehold expenditures, since capitalized leasehold investments reflect only about 25 percent of total leasehold expenditures, and the South Louisiana data include offshore costs. Nevertheless, since these data provide the only available benchmark, the split will be made in proportion to drilling expenditures, resulting in the allocation of 15 percent to onshore Louisiana and 85 percent to the remaining U.S. The computation of unit cost per barrel is shown on page 188:

[1] This point is, of course, also applicable, though perhaps to a lesser degree, to the measurement of drilling cost. Limiting that measurement to offshore Louisiana was largely due to the availability of data; moreover, the drilling effort in offshore Texas was relatively small prior to 1964, so that its inclusion would not significantly change the results shown for offshore Louisiana.

[2] Chase Manhattan Bank, *Capital Investments in the Petroleum Industry*, Annual Reports.

[3] The 18 percent figure reflects the data for producers excluding pipelines; the 24 percent figure includes pipelines. The inclusion of pipelines raises the ratio of lease acquisition to well investments, because pipelines frequently purchase developed properties, where the price of the lease reflects in part the capitalized value of discovered reserves.

	Cost of Leasehold Acquisitions		
	Gulf of Mexico	Onshore So. La.	Other U. S.
1. Estimated 1954-1964 expenditures (million $)	1,326	700	3,974
2. Reserve additions 1956-1966 (equivalent bbl)	4,939	5,805	31,622
3. Unit cost (cents per equivalent bbl.) (Lines 1 ÷ 2)	26.8	12.1	12.6

Source: Line 1 - see text.
Page 209, line 2 - Table 5; gas converted barrels of oil on a revenue basis.

For no single cost component is the cost differential as great as for leasehold costs. As shown in the above table, the cost of offshore leases is twice as high as the cost of onshore leases.

It should be noted that in the above computation the 1954-1964 expenditures were related to reserve additions for the period 1956-1966, i.e., the lag between the acquisition of leases and the reporting of reserve additions was assumed to be two years. That assumption is strained, since the acreage from the 1962 and 1964 lease sales was obviously not fully drilled up by the end of 1966. The choice of the two-year period was only partly influenced by the data on time lag discussed below; a more significant consideration was the desire to exclude any reserve additions resulting from the 1966 offshore lease sale.

a. The allocation of lease acquisitions

The gap between what is conceptually appropriate and practically feasible is even wider in the allocation of lease acquisitions than it is for dry holes. To the extent the exploratory effort is directional—in the sense of knowing whether the structure is primarily oil or gas bearing—it is conceptually possible to make direct assignments of bonus costs. However, with minor exceptions, such data are not yet available. Recourse must thus be had to allocation techniques which are heavily dependent on the exercise of discretionary judgment.

Perhaps the most realistic technique, which may come closest to an approximation of cost incurrence, is to allocate total bonus costs in proportion to the cost of gas and oil acreage transferred to productive properties. If all leases were productive (and none surrendered, abandoned, or cancelled), then the cost of lease acquisitions would become directly identifiable with oil or gas reservoirs. However, on a national basis, only 25 percent of lease acquisitions are productive, whereas offshore about 70 percent are productive. To allocate lease acquisitions in proportion to the cost of gas and oil acreage transferred to productive properties is to assume that the unsuccessful costs should be distributed in proportion to the successful costs. In the absence of evidence to the contrary, such as different success ratios for gas and oil, this constitutes the most reasonable assumption. Data adduced at FPC hearings show that, on a national basis, an allocation in proportion to the cost of gas and oil acreage transferred to productive properties would have charged about 48 percent to gas and 52 percent to oil in the period 1955-1962.[1] Although similar data are not available for offshore and onshore Louisiana, the figure is a useful benchmark in evaluating the results of other techniques.

Accepting the above premise as valid, virtually identical results are obtained by an application in proportion to well costs, with appropriate modification for the degree to which the relation between lease acquisition to well costs differs between oil and gas reservoirs. To illustrate, data collected by the FPC showed that the ratio of leasehold to well investments was approximately 20 percent for United States, excluding South Louisiana (page 222). If that ratio were the same for gas and oil leases, then an allocation in proportion to well cost

[1] FPC Dockets AR64-1 and AR64-2, Exh. 42-J, Sch. 6.

would be equivalent to an allocation in proportion to the cost of productive acreage. However, the data indicate that the relation between leasehold and well costs is 30 percent greater for gas than for oil leases in the U.S. excluding South Louisiana,[1] and at least 75 percent greater for gas leases in South Louisiana.[2] Therefore, the allocation in proportion to well cost must be adjusted for the relatively greater cost of gas leases as compared to oil leases. Of course, in making the adjustment, account must be taken of the relative expenditures made for gas and oil wells.

An alternative approach is to allocate lease acquisition costs in proportion to the value of reserve additions, sometimes referred to as the reserves added realization method. The rationale for such an approach is that the value of what has been found is the lust approximation of what producers were looking for of course, any recourse of value measurements in the allocation techniques is to abandon the search for an approximation of cost incurrence; it is equivalent to distributing costs in proportion to the ability to bear costs. However, in the instant study this technique is consistent with the use of a similar value measurement in converting the gas reserves into equivalent barrels of oil reserves.

The technique of applying the reserves added realization method is more complex than its rationale. Since the technique is to be applied to a component of exploration cost, the value of reserve additions should be measured by reference to the value at this particular stage of exploration, i.e., by reference to below-ground rather than above-ground values. An accurate determination of below ground values is, of course, not possible, but an approximation may be obtained by deducting from the prices received the cost of lifting, production taxes, royalties, and transportation cost (for offshore). The thus reduced prices must be further adjusted (discounted here at 7 percent) for differential depletion patterns of oil and gas reservoirs, because the value of reserves is dependent on the timing of the receipt of revenues. The discounted below-ground present values of the respective oil and gas reserviors were computed at:

	Estimate of Below-Ground Values	
	Oil Reservoirs ($/bbl)	Gas Reservoirs (¢/Mcf)
Offshore Gulf of Mexico	1.38	8.89
Onshore So. Louisiana	1.31	9.79
U.S., excluding Gulf of Mexico and South Louisiana	0.88	7.12

The results of applying the three alternative allocation techniques discussed above are shown in the first table on the following page.

For onshore and remaining U.S., the leasehold acquisitions will be allocated in proportion to drilling cost with appropriate adjustments for the relatively higher cost of gas leases, because that method yields a closer approximation of cost incurrence than the reserve added realization method. However, in view of the absence of data on the relationship between leasehold and well costs for offshore operations, the allocation of offshore leasehold costs will be expressed in terms of a range, defined by the reserve added realization method and an allocation in proportion to drilling costs, adjusted for the presumed higher cost of gas leases. An allocation in proportion to drilling costs, unadjusted, would probably overstate the cost attributable to oil reservoirs. The results of applying these respective methods are shown on the second table on the following page.

VIII. Geophysical, Geological and Other Exploratory Costs

As previously noted, all exploration activities are national in scope; the knowledge gained in one area is available in other areas. Any attempt to compute an area cost for geophysical and geological expenditures is thus of limited economic significance.

The most appropriate measurement of geophysical activity is made by reference to miles of line shot. However, available data permit the quantification of geophysical activity only in terms of seismic, gravitometer and magnetometer crew months. As shown on page 223, the number of offshore crew months fluctuates widely. Peaks were attained in 1947-1948 and 1955-1956; declines were experienced in the early and late 1950's. The 1960's have been characterized by a gradual increase, so that by 1966

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[1] The ratio of leasehold to well investments is 26 percent for gas and 20 percent for oil, so that there is a 30 percent differential (page 222).

[2] The data (page 222) indicate a 75 percent differential excluding pipelines (30.5 ÷ 17.5 = 174 percent) and a 200 percent differential including pipelines (52 ÷ 17.5 = 297 percent).

Allocation in proportion to	Allocation of Leasehold Costs: Offshore Gulf of Mexico: Oil Reservoirs	Offshore Gulf of Mexico: Gas Reservoirs	Onshore So. La.: Oil Reservoirs	Onshore So. La.: Gas Reservoirs	Other U.S.: Oil Reservoirs	Other U.S.: Gas Reservoirs
	(Percentages)					
1. Drilling expenditures	68	32	57	43	70	30
2. Drilling expenditures adjusted for the relatively higher cost of gas leases	54[a]	46[a]	43	57	64	36
3. Value of reserve additions	62	38	54	46	72	28

[a] Based on the assumption that the relation between leasehold and well costs is 75 percent greater for gas leases than for oil leases.

	Allocated Cost of Leaseholds: Gulf of Mexico	Onshore So. La.	Other U.S.
Oil reservoirs (cents/bbl)	25-28	10	11
Gas reservoirs (cents/Mcf)	1.82-2.21	1.15	1.26

Source: Page 206, Table 2; page 207, Table 3; page 208, Table 4.

the offshore seismic crew months' activity was within 10 percent of the 1955 peak.

The costing of geophysical activities, in terms of a current unit cost related to recent reserve additions, presents unusual difficulties, requiring the resolution of partly conflicting conceptual considerations. The bulk of geophysical activity precedes the bidding on leases by approximately two years. The recent high level of offshore geophysical activity was undoubtedly related to the 1966 and 1967 federal offshore lease sales, and may thus be viewed as a cost of future reserve additions, the magnitude of which is unknown. Consistency with the determination of lease acquisition costs by reference to 1954-1964 expenditures would require the measurement of geophysical costs by reference to expenditures in the period 1952-1962, assuming geophysical activities precede lease sales by two years. However, there has been a substantial change in both geophysical technology and the cost per crew month. The knowledge obtained per crew month has continued to increase with the introduction of newer equipment; the cost per month has also more than tripled in the last 15 years. Whether the improvements in technology have exceeded or fallen short of the rise in cost is not readily ascertainable. Reliance on the experience of a past period as a measure of current cost would assume that these two factors were balanced.

For the measurement of geophysical costs, the above conflicting conceptual considerations are here resolved in favor of reliance on expenditures during

the most recent five years for which data are available, 1962-1966. Thus, the unit cost will reflect not only the current cost per crew month, but also a higher level of geophysical activity than prevailed during the period 1952-1962. The latter period is rejected because of the uncertainty whether the improvements in technology have matched the rise in dollar cost per crew month, and because reliable figures on the cost per crew month have only recently become available. It is possible that reliance on recent geophysical expenditures, reflecting the enhanced activity preceding the 1966 and 1967 federal lease sales, wi.l overstate the unit cost per barrel of recent reserve additions. However, an overstatement would arise only if future reserve additions, in relation to the geophysical activities, were to be significantly higher than recent reserve additions. The probability of such an overstatement is not great. The higher recent geophysical activity is partly due to the prospecting at increasing distances from onshore.

The table below sets forth the estimated average annual expenditures for geophysical and other exploratory costs:

	Gulf of Mexico	Onshore So. La.	Other U.S.
		– (Millions of Dollars) –	
Geophysical expenditures	42.8	25.5	123.4
Geological expenditures	28.5	17.0	82.3
Lease rentals	6.7	28.0	159.0
Land, leasing and scouting expenses		16.2	92.2
Other exploratory expenses	7.8	8.7	45.7
Total	85.8	95.4	502.6

The estimate of *geophysical expenditures* is based on the 1962-1966 crew months of geophysical activity (page 223) and a cost per seismic crew month of \$190,000 for offshore, \$50,000 for onshore Louisiana, \$33,000 for Other United States, and a cost of \$15,000 per gravitometer and magnetometer crew month.[1]

With minor exceptions, data on geological and other exploratory costs are available only on a national basis. The distribution of expenditures between the three areas under study therefore rests on largely arbitrary allocations.

The estimate of *geological expenditures* is based on the relationship between geological and geophysical expenditures, shown by the Joint Association Survey (JAS) for the most recent five-year period (1961-1965) available; i.e., geological costs are computed at two-thirds of geophysical costs.

Lease rentals for Gulf of Mexico reflect average annual rentals collected by the Federal Government and the State of Louisiana (1963-1967); for onshore South Louisiana and the remaining U.S., the figures are based on the relationship between lease rentals and lease acquisition costs. As shown by the JAS (1961-1965), lease rentals were 44 percent of lease acquisition costs (excluding Gulf of Mexico).

The *land, leasing*, and *scouting expenses* incurred offshore are negligible; for onshore South Louisiana and the remaining U.S., the figures reflect JAS data (1961-1965) distributed between the two areas in proportion to lease acquisition expenditures.

Other exploration costs were estimated at 10 percent of the sum of geophysical, geological, lease rentals, land, leasing, and scouting expenses, based on ratios derived from the JAS.

The total dollar expenditures shown above were allocated between oil and gas reservoirs on the basis of the value of reserve additions (1963-1967), thereby charging 68 percent to oil and 32 percent to gas.[2] The resulting unit costs are shown on the table on the following page.

[1] The cost per crew month is based on data collected from companies and Annual Reports of the Committee on Geophysical Activity of the Society of Exploration Geophysicists.

[2] See *supra*, p. 63.

	Geophysical and Other Exploratory Costs		
	Oil Reservoirs	Gas Reservoirs	Total Hydrocarbons
	(¢ /bbl)	(¢/Mcf)	(¢ bbl.)[a]
Offshore Gulf Of Mexico	16	1.00	15
Onshore South Louisiana	21	1.58	20
Other U. S.	16	1.34	17

a/ Gas converted to equivalent barrels of oil on a revenue basis.

The above results show that the costs of Gulf of Mexico geophysical and other exploratory activities are somewhat lower than onshore activities. However, no significance is attached to the rather wide differences shown for the cost of gas reservoirs because the dispersion results primarily from the use of a discretionary allocation technique.

IX. Production Operating Expenses

Production operating expenses consist primarily of expenditures for labor and materials to operate the well and to perform maintenance and workover tasks. For onshore operations, the cost per well is a function of both depth of wells and number of wells in the field, since a larger concentration of wells can be handled with proportionately less labor. In offshore operations, distance from shore constitutes a third cost variable.

The measurement of operating costs, for purposes of this study, is complicated by the need to estimate costs over the entire producing cycle of the reservoirs. Within the realm of practicability, two simplified alternatives suggest themselves. One is to estimate operating costs at a constant amount per year; the other, at a constant amount per barrel or Mcf. Both techniques have defects, so that the problem is to select the one with the least serious deficiencies.

At a constant per barrel or Mcf basis, operating costs tend to be overstated in the early life of the reservoirs and understated in the later life, because production rates are higher in the earlier than in the later stages. A constant annual producing cost therefore appears a better approximation of the expenses per well than a constant per barrel or Mcf figure. However, the instant study seeks to approximate the industry cost of reserve additions reflecting a large number of wells. Many wells will be abandoned long before the "average" reservoir is depleted, so that the total annual level of operating costs will be reduced from the initial level as the wells are abandoned. Thus, the use of a constant annual producing cost would understate the early life and overstate the later life cost; in the context of a discounted cash flow study, it would overstate the return earned. The use of a constant per barrel or Mcf operating expense throughout the life of the reservoirs tends to overstate the present worth of the operating expense and understate the return earned. Nevertheless, the latter technique will be used in this study, primarily because the measurement of operating costs will be made by reference to data which tend to understate the operating costs, thereby offsetting the theoretical understatement of the return.

Data on operating expenses for South Louisiana and Continental U.S. are available from responses to FPC questionnaires sent to approximately 80 producers, including virtually all "majors". These data are for the years 1960 and 1962, and reflect the average operating cost incurred on leases of recent and old vintages. Reliance on these data thus assumes that the average cost of the mix of different vintage leases is the same as the average for a group of recent vintage leases over their entire life. This assumption would be valid only if the properties producing in 1960 or 1962 represented all stages of depletion in approximately equal proportions. The latter condition is difficult to judge, but an approximation may be obtained by reference to the relation between net and gross investment in producing properties. If it is close to 50 percent, it would indicate that the properties producing in 1962 were on the average half depleted, which would suggest a fairly equal distribution between recent and old vintage

properties. The data, however, indicate that the FPC sample contains a relatively high proportion of recent vintage leases. For South Louisiana, the ratio of net to gross investment was approximately 70 percent for oil leases and 75 percent for gas leases; for the Continental U.S., the ratio was approximately 40 percent for oil leases and 66 percent for gas leases. Thus, with the exception of the Continental U.S. data for oil leases, the cost per barrel or Mcf derived from the FPC collected data tend to be understated (see page 192.

An analysis of the FPC collected data shows the following unit production operating costs, which will be used in this study:

	Onshore So. Louisiana	U.S., Excluding So. Louisiana
Oil and oil casing-head leases (¢/bbl)	51	55
Gas and gas condensate leases (¢/Mcf)	2.34	1.74

Source: FPC Docket AR61-2, Exhs. 47 and 48; AR64-1 and AR64-2, Exhs. 1, 4, 7 and 10.

Note: The unit costs are net of royalties and adjusted for inclusion of offshore costs.

Data for *offshore* operating costs are not publicly available, so that a special collection effort was undertaken for this study. Figures supplied by companies accounting for over 50 percent of offshore Gulf of Mexico production suggested the following average costs:

Oil reservoirs	33 cents per bbl.
Gas reservoirs	2.75 cents per Mcf
Total hydrocarbons	35 cents per equivalent barrel

On a unit of production basis, offshore operating costs are thus lower than onshore costs.

As previously noted, the principal cost variables in offshore production costs are number of wells per field, depth of well, and distance from shore. The impact of the depth of well (for a typical offshore field) is shown in the following table:

Well Depth (feet)	**Cost per Well per Month**
2000 - 8000	$1300 - $1500
10,000 - 12,000	$1700 - $1850
14,000 - 16,000	$2050 - $2300

The impact of distance from shore is approximately $2500 per year per completion for every additional 20 miles from the coastline.

X. **Offshore Transportation Costs**

The transporting of oil and liquids from offshore producing platforms to onshore delivery points takes place either in pipelines or by barge; transportation of gas is always by pipeline. The cost of transportation, although not a major item in the past, will become of increasing significance in the future. In general, transportation costs per barrel or per Mcf are considerably higher offshore than onshore. The major factors accounting for the relatively higher offshore transportation costs are the greater capital equipment needed for construction in the form of pipelaying barges, the longer construction time required due to variable weather conditions, the greater thickness of pipe needed to withstand the stresses of currents in deep water, and many other extra costs, such as concrete coatings to hold the pipe to the ocean floor and longer pipelaying stingers. The most significant cost variables are throughput (or production), distance from shore, and water depth.

a. **Cost of transporting oil and condensate**

A substantial, though declining, proportion of oil is transported by *barges.* The cost of transporting by barge varies both by size of load and distance from shore. A typical pricing schedule for a barge, with a speed not exceeding 5 miles per hour, is as follows:

Maximum Size Load	**Daily Rate**
16,000 bbl.	$ 800
20,000 bbl.	950
25,000 bbl.	1,100

The most significant time element in barging is loading and unloading, which is heavily dependent on weather conditions. For transportation of oil produced within 25 miles of the terminal, the barging

cost ranges from 8 to 18 cents per barrel for the more remote areas, the typical barge costs range from 25-35 cents per barrel. Although distance from shore is not the only factor affecting barge costs, a cost of 0.4 cents per barrel per mile constitutes a rough approximation.

When the production rate of a field exceeds 10,000 barrels per day, the investment required for conventional storage facilities becomes uneconomical in comparison with transportation though pipeline. By 1968, approximately 500 miles of oil pipelines had been constructed in the Gulf of Mexico,[1] and the rate of construction was accelerating. The cost of constructing pipelines is a function of the diameter of the pipe, distance from shore, and water depth. The cost of transporting oil through pipelines may be gleaned from tariffs filed with the Interstate Commerce Commission by those pipelines which are common carriers. In general, there is a relation between cost per barrel and distance transported; however, for the shorter distances there is a wide range of costs, varying inversely with the throughput capacity of the line. The following table shows the cost per barrel related to distance from shore, based on both tariffs filed with the ICC and data collected from individual companies:

Distance from Onshore Terminal	**Transportation Cost - ¢/bbl.**
10 miles	3 - 5 cents
10-20 miles	4.5 - 8.5 cents
20-35 miles	8 - 14 cents
40-50 miles	25 - 30 cents
55-75 miles	34 - 40 cents

The cost of transporting oil through pipelines is thus between one-half and two-thirds of the cost of barging. Since reserves for which a cost estimate is made in this study are predominantly located within 35 miles of onshore terminals, the average transportation cost for crude oil and condensate separated at the platform has been estimated at 12 cents per barrel. This estimate is, of course, an understatement of the cost which will be incurred in the future.

b. Cost of gas transportation

The cost of transporting the gas stream has been omitted from this study[2] because the cost of offshore transportation is typically borne by the gas pipelines. The price used for the estimate of revenues received by producers is a wellhead price, so that the cost of transportation need not be considered in computing the profitability of the gas reservoirs. Neverless, the cost of offshore gas transportation is of interest, for two reasons. First, it has a bearing on the economics of offshore exploration, since offshore gas supplies compete with alternative gas supplies. As reserves are found at increasing distances from shore, the cost of transportation will set an economic limit to the price pipelines are willing to pay. Second, the gas reservoirs contain natural gas liquids which are extracted in onshore plants. Although at the present time the pipelines bear the cost of transporting the commingled gas-liquid stream, the FPC has announced its intention of promulgating rules for the allocation of the cost of transportation between gas and liquids.[3] Such allocation would reduce the cost of gas to the consumer, and would prompt the pipelines to negotiate with the producers for compensation for the transportation of liquids.

As in the case of oil pipelines, the cost of constructing gas pipelines is higher offshore than onshore. As shown in the following table, the cost per miles is significantly influenced by water depth. (See table on the next page.

The annual cost of operating a pipeline (including a return on net investment of about 6.5 percent and income taxes) ranges between 15 and 20 percent of capital costs. The cost per Mcf is, of course, dependent on the magnitude of the throughput from the dedicated reserves. To illustrate, if a 50-mile, 30-inch pipeline were constructed in water depth below 100 feet, the total cost would be about $16.5 million, and the annual cost about $2.5 - $3.0 million. Assuming the dedicated reserves were 2 billion Mcf, and the annual throughput averaged 100 million Mcf, the unit cost would range from 2.5 to 3.0 cents.

An estimate of the impact of distance and throughput on cost may be gleaned from FPC cost findings. The cost of transporting gas over a distance of ten miles ranged from 0.25 cents to 0.63 cents per Mcf.[4] For a recently constructed pipeline extending 50 miles offshore, the transportation charge is 4¢/Mcf for the first 80,000 Mcf per day and 2 cents for additional volumnes.[5] In certificating a pipeline for a

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[1] *Oil and Gas Journal*, October 7, 1968; 1969 *Crude Oil Pipeline Atlas.*

[2] Except for the cost of transporting condensate separated at the platform, estimated at 12 cents/bbl., which is equivalent to 0.23 cents per Mcf.

[3] Notice of Proposed Statement of General Policy, Docket No. R-338, February 5, 1968.

[4] Examiner's decisions in Dockets CP63-26 and G-16669.

[5] FPC Docket CP68-323.

GULF OF MEXICO

TYPICAL GAS PIPELINE COST PER MILE IN RELATION TO PIPE DIAMETER AND WATER DEPTH

Pipeline Diameter	Water Depth 0 - 100 ft.	Water Depth 100-200 ft.	Water Depth 300-350 ft.
	(Dollars)		
36 incles	435,000		
30 "	330,000	475,000	
26 "	250,000	310,000	
24 "	225,000	275,000	400,000
20 "	180,000	220,000	325,000
12 "	100,000	125,000	165,000

Source: Data derived from applications for certificates of public convenience and necessity filed with the Federal Power Commission in 1965-1968.

distance of 76 miles offshore, the Commission referred to a cost of 8.1 cents per Mcf for deliveries of 50,000 Mcf per day, which would, however, decline to 2.56 cents if the deliveries increased to 150,000 Mcf per day.[1] For a pipeline system of varying pipe diameter with branch lines stretching over a distance of some 150 miles, the costs were estimated at 3.7 cents per Mcf per 100 miles.[2] Whether these costs will prevail in the future is uncertain because the FPC may be undertaking a fundamental policy review in its certification of offshore pipeline projects. Hitherto, approval of offshore pipelines has been on a piecemeal basis, with individual pipelines reaching out to whatever reserves they had attached under contracts. In 1966, an integrated proposal of several producers for the construction of a "header line" with multiple branch lines for gathering reserves over a wide area was rejected by the FPC.[3] However, a recent study[4] prepared for the FPC on techniques for evaluating the design of pipeline systems suggested that considerable savings (up to 50 percent) could have been obtained if the offshore network had been designed to achieve a minimal cost design of pipeline systems, given presently existing gas field locations and flow requirements. Of course, the savings are hypothetical, since they assume, *ex post*, the existence of the fields which are now producing at the time the pipelines were constructed, when in fact the knowledge as to existence of reserves at the time of pipeline construction was quite different. Nevertheless, it is possible that the FPC will emphasize greater "planning" in the construction of pipeline facilities and may require pipeline to pool their resources and attachment of reserves in order to achieve cost savings.

The impact of the FPC proposal to require the allocation of gas pipeline transportation costs between gas and liquids is also difficult to estimate. In all probability, the pipelines will seek reimbursement from producers of the costs allocated to liquids. The charges to producers will, of course, depend on the throughput of the line and the length of the haul. An approximation of such charges may be obtained from two recently proposed tariffs, ranging from 6 cents per barrel for a 50-mile line[5] to 20 cents for a 56-mile line.[6] Whatever charges are

[1] FPC Docket CP67-259.

[2] Examiner's decision in Docket CP66-168, and applications for certificates in Dockets CP69-50, 69-53 and 68-231.

[3] Application by "Red Snapper", FPC Docket CP66-168.

[4] *Design of Economical Offshore Natural Gas Pipeline Systems*, Office of Emergency Preparedness, National Resource Analysis Center, Systems Evaluation Division, November 1968.

[5] Docket CP65-323.

[6] Docket CP68-323.

made will, of course, reduce the indicated level of profitability of gas reservoirs computed in this study.

XI. Production Taxes and Overhead

a. Production taxes

No state production taxes are levied on hydrocarbon production from federal offshore leases. The only production taxes payable arise in connection with the extraction in onshore plants of natural gas liquids produced offshore estimated at 0.03¢/Mcf for condensate and 0.01¢/bbl. for associated plant liquids.[1]

For onshore Louisiana, the following tax rates were used:

Gas	2.3¢/Mcf
Oil and condensate	20¢/bbl.
Plant liquids, other than condensate	2¢/bbl.

For the U.S. excluding South Louisiana, the following average state tax rates were used:

Gas and plant liquids	6.5% of value
Crude oil and condensate	4.5% of value

These rates reflect approximations of average tax rates (weighted by reserve additions) in the States of Texas, Oklahoma, Kansas, North Louisiana and Mississippi. Since the royalty owner is responsible for the payment of production taxes applicable to his share of production, the production tax figures shown on the summary tables 1 to 4 reflect an adjustment for royalties.

b. Overhead expenses

Overhead expenses were estimated at 10 percent of total finding, production, and other costs, based on Joint Association Survey as well as data collected by the Federal Power Commission. There is no basis for a finding that overhead costs incurred offshore are disproportionate to those incurred onshore or that they are disproportionate for oil as compared to gas reservoirs. Thus, the same 10 percent factor has been applied to the total outlays in each area and for each of the respective reservoirs.

[1] Consistency with the computation of the other cost items would require the use of a higher unit production tax, because the reserve additions for which a cost is here estimated include state leases on which production taxes are payable. However, since the inclusion of state leases was due solely to the limitation of data on reported reserve additions, and the primary purpose of this study is to estimate the cost pertaining to reserve additions of federal leases, an inclusion of state production taxes would not be appropriate.

XII. Revenues and Royalties from Oil and Gas Reservoirs

In estimating unit cost, each of the above described cost components was related to reserve additions (or production volume) of either crude oil or non-associated gas. These estimates reflect the total cost of all products of the oil and gas reservoirs respectively, related solely to volumes of crude oil and non-associated gas. However, crude oil reservoirs produce not only oil, but also associated gas and natural gas liquids; non-associated gas reservoirs produce not only natural gas, but also condensate and other liquids extracted in processing. To avoid an understatement of profitability, total revenues from the respective reservoirs must be matched against total costs. If costs are expressed in unit per barrel or Mcf of the major product of the reservoirs, the total revenues must be similarly expressed, e.g., the unit revenues per barrel from oil reservoirs must be augmented by the revenues (in cents per barrel) from the other products emanating from oil reservoirs.

a. Revenues from crude oil reservoirs

Revenues from crude oil reservoirs are estimated as follows:

	Revenues from Crude Oil Reservoirs		
	Gulf of Mexico	Onshore So. La.	Other U. S.
	(In dollars per barrel)		
Crude oil	$3.13	$3.13	$2.85
Associated gas	.23	.40	.05
Associated gas liquids	.02	.05	.05
Total	$3.38	$3.58	$2.95

Source: Page 224, Table 20.

The revenue figures for *crude oil* reflect the 1967 average wellhead revenues reported by the Bureau of Mines.[2] The revenue estimates for *associated gas* reflect the following factors (set forth on page 224). The starting point is the ceiling prices for interstate gas deliveries set by the Federal Power Commission. Since the associated gas is typically produced at low pressures, the respective prices were reduced by compression charges. The net revenue figure was then converted to revenues per barrel on the basis of the Mcf of associated gas reserve additions in relation to crude oil reserve additions.

[2] The Gulf of Mexico and onshore South Louisiana unit revenues were assumed to be the same as for total Louisiana.

The final step is to estimate the split of revenues between producers and processors. In South Louisiana, the associated gas is relatively lean and of high pressure, compared with other areas. The producers typically sell the gas to the pipelines directly, whereas in other areas the associated gas is sold to processing plants, which compress the gas, strip it of liquids, and sell the residue gas to pipelines. Producers in South Louisiana typically receive the value of the full stream of gas (after deduction for shrinkage and fuel in processing plants when liquids are extracted), whereas in many other areas gas is typically sold under so-called "percentage type" contracts, under which producers receive only a portion of the revenues realized by the processor.

The estimation of the revenues received from *associated gas liquids* is even more complex. The starting point is a computation of the liquid content of the gas stream in terms of gallons per Mcf, the so-called GPM. For reasons previously discussed,the GPM cannot be estimated on the basis of reported reserve additions, so that the computation must be made by reference to production volumes and remaining reserves. For South Louisiana, production data show the GPM at about 1.0 and the remaining reserves indicate an approximately 33 percent lower liquid content for offshore than for onshore. The GPM was therefore estimated at 0.8 for offshore and 1.20 for onshore South Louisiana; the corresponding figure for the remaining U.S. is estimated at 3.00. The GPM must then be converted into gallons per barrel of crude oil, based on the Mcf of associated reserve additions per barrel of crude oil reserve additions, multiplied by the price per gallon and reduced for shrinkage and fuel loss of gas volumes. Of the thus computed revenues, producers received only 35 percent; the remainder accrues to the plant owners for the service performed in processing the gas. In arriving at the 35 percent estimate, consideration was given to both the percentage of revenues credited back to the lease and the fact that producers do not in all cases reserve the right to share in liquid revenues received from processing.

b. Revenues from non-associated gas reservoirs

Revenues from non-associated gas reservoirs were estimated as follows:

	Revenues from Non-Associated Gas Reservoirs		
	Gulf of Mexico	Onshore So. La.	Other U. S.
	(Cents per Mcf)		
Non-associated gas	18.14 ¢	19.61 ¢	17.00 ¢
Lease and plant condensate	6.14	8.08	2.32
Other plant liquids	.58	.87	1.33
Total	24.86 ¢	28.56 ¢	20.65 ¢

Source: Page 225, Table 21.

Revenues from *non-associated* gas for offshore and onshore South Louisiana reflect the 18.5 cents and 20.0 cents (at 15.025 psia) recently set by the FPC in Opinion 546 (AR61-2) for interstate sales; the 17.0-cent price for the remaining U.S. reflects average prices of interstate contracts negotiated in recent years, as well as the price set by the FPC in *Permian Basin* (Opinion 468 in AR61-1), Examiner decisions and Staff recommendations in cases pending before the Commission.[1]

The estimates of *condensate* revenues are based on production data (since reserve additions of natural gas liquids cannot be reliably computed). The average 1966-1967 condensate yield of non-associated gas was 19 barrels per MMcf in offshore Louisiana, 25.0 barrels in onshore Louisiana, and 7.25 barrels per MMcf in the Other U.S. Applying these liquid yields

[1] Prices for intrastate gas deliveries, although not publicly available for most sales, have been approximately the same as for interstate deliveries except in recent years, when they have been higher than regulated interstate prices.

to the 1967 South Louisiana and Other U.S. condensate prices of $3.23/bbl. and $3.20/bbl. results in the revenue per Mcf shown above.

The estimate of revenues from *other plant liquids* (LP gases, ethane, natural gasoline and isopentane) necessitates, as a first step, an estimate of the liquid yield—the GPM. The technique of estimating, shown in Table 21, indicates a GPM of 0.37 for South Louisiana and 0.80 for Other U.S. Since plants for processing of offshore natural gas have only recently been installed, the indicated GPM for South Louisiana may understate prospective recovery yields. In view of this fact, the GPM was adjusted to 0.35 for offshore and 0.50 for onshore. As shown in Table 21, multiplying these respective GPM's by the revenues per gallon, making allowance for a 2 percent shrinkage and fuel loss, and again estimating the proportion of revenues credited back to the lease at 35 percent, resulted in the respective revenues of 0.58 cents, 0.87 cents and 1.33 cents per Mcf shown above.[1]

c. Royalties

Royalties currently applicable were estimated as follows:

Gulf of Mexico	16.67%
Onshore So. La.	15%
U.S., excluding So. Louisiana	13%

The above figures are based on the prevailing 1/6 royalty for federal leases and on data collected by the FPC showing the national average royalty cost at 14.5 - 15.5 percent.[2]

[1] Since the condensate and plant liquid revenues are estimated on the basis of production rather than reserve additions, a test of the reasonableness of these estimates is in order. Such a test, although of limited value, can be made by reference to remaining reserves. In a period when the liquid yield of remaining reserves of NGL in relation to remaining reserves of non-associated gas increases, it could be argued that the estimate of prospective yield should not be below that of remaining reserves. That criterion neglects the fact that the increasing liquid yield may be significantly affected by the installation of new processing facilities.

Setting aside this limitation, it will be recalled that for offshore Louisiana the condensate yield (of production volumes) was 19 bbl/MMcf; the GPM was estimated at 0.35, or 8.3 bbl/MMcf. The total yield used for purposes of this study is therefore 27.3 bbl/MMcf, which is approximately 10 percent above the 24.2 bbl/MMcf of remaining reserves.

Similar tests for onshore Louisiana show the estimate (implicit in the revenue figures) at 36.9 bbl/MMcf, as compared to remaining reserves of 36.7 bbl/MMcf; for the Other U.S., the estimate is equivalent to 26.3 bbl/MMcf, compared to 22.9 bbl/MMcf on the basis of remaining reserves.

[2] FPC Dockets AR64-1 and AR64-2, Exh. 41-J.

XIII. Preproduction Time Lag

The time that elapses between making an expenditure and the commencement of the receipt of revenues from that expenditure is an economic cost. Utilities typically capitalize that cost by adding interest during construction to the cost of the installation. Oil companies do not capitalize the cost of waiting on their books of accounts; nevertheless, the waiting period before the commencement of the revenue flow is as significant a factor affecting the return earned as the timing of revenues during the depletion of the reservoirs. However, that waiting period is only part of what is usually referred to as the "time lag"; an additional waiting cost is incurred between the commencement of the flow of revenues and the attainment of the full rate of production from the reservoirs. The latter is reflected in the buildup period of the depletion curves (see Section 14).

a. Time lag for offshore (Gulf of Mexico) expenditures

An accurate measurement of time lag is an extremely complex undertaking, requiring detailed data on both expenditures and the receipt of revenues on a lease-by-lease basis. That kind of data is not readily available, and its collection would not have been possible within the budgetary limitations of this study. To obtain an approximation of the time lag for offshore operations, selected accounting records from the U.S. Geological Survey were examined for the purpose of determining the date of initial receipt of revenues, and drilling records were examined to determine the date of commencement of drilling operations. Additional data, particularly for the time lag of geophysical expenditures, were collected from several large offshore producers.

(1) *Drilling time lag:* An analysis of the data gathered from the U.S.G.S. showed the following results on the average time lag (in months) between the commencement of drilling and the initial receipt of revenues (the number of wells surveyed is shown in parentheses on the following page).

The 1st table data do not reflect a random sample; the coverage of wells was constrained by the readily available records on initial receipt of revenues. Moreover, the above results reflect only the time lag for drilling activity undertaken prior to the first receipt of revenues—i.e., most of the data reflect the early drilling on the lease, so that the results may be heavily weighted with exploratory wells. The time lag

Time Lag for Drilling Wells

Federal Lease Sales (Gulf of Mexico)	Oil Wells		Gas Wells		Dry Holes[a]	
	Months Time Lag	No. of Wells	Months Time Lag	No. of Wells	Months Time Lag	No. of Wells
1954, 1955 and 1959	14.5	(98)	39.8	(64)	27.2	(158)
1960	9.1	(33)	24.7	(71)	25.5	(55)
1962 & 1964	9.1	(178)	13.1	(29)	19.9	(172)

[a] Although no revenues are obtained from dry holes, the expenditures for dry holes are a part of finding costs, the timing of which enters into the determination of the yield on capital committed. The time lag for dry holes reflects the number of months elapsed between the commencement of drilling and the receipt of revenues from leases on which productive wells were also drilled.

on development wells is shorter. However, the overall time lag for the total dollar outlays in development drilling may be as long as for exploratory wells because construction of platforms precedes development drilling and the platforms represent a substantial proportion of total development cost.

The above table permits only two firm conclusions. First, the waiting time is longer in drilling for gas than for oil. This is largely due to the delays attending the construction of gas pipelines and the necessity to obtain approval by the FPC, usually entailing lengthy procedural delays. Second, the time lag has become shorter as time progresses. This trend is due to greater experience in offshore operations and the increasingly larger outlays for lease bonuses which act as a spur to more rapid development.

For purposes of this study, the following offshore time lags will be used:

Oil well drilling and equipping costs	9 months
Gas well drilling and equipping costs	24 months
Dry holes	18 months

These conclusions are generally based on the time lag data computed from the 1962 and 1964 lease sales except for gas, where the data showing only 13 months time lag were disregarded, partly because the number of wells covered was relatively small and partly because present FPC practices are unlinely to result in waiting periods of less than two years.

2. Lease bonus time lag

The analysis of the available sample data shows the following average months of lag (weighted by dollar expenditures) between the time of the lease sale and the initial receipt of revenues from production (bonus expenditures covered in the sample are shown in parentheses on the table below).

As already noted, these data do not reflect a random sample; the coverage was constrained by

Time Lag for Lease Bonuses

Lease Sale	Oil		Gas	
	Months Time Lag	Bonuses (Millions Dollars)	Months Time Lag	Bonuses (Millions Dollars)
1954, 1955 and 1959	39	(173)	49	(123)
1960	36	(64)	50	(85)
1962	35	(113)	40	(49)

readily available records on initial receipt of revenues. They again show that the time lag is longer for gas than for oil, and that there is a trend in the direction of a lesser time lag. The data suggest that the average time lag for primarily oil leases is three years and for gas leases approximately four years.

3. Time lag for other exploratory costs

Data collected from a number of companies show that geophysical expenditures are made, on the average, about 2-3 years ahead of lease acquisitions. Geological expenditures are on the average made two years prior to the receipt of revenues. The timing of lease rentals is the same as for lease acquisitions. When these relative time lags are weighted by the respective magnitudes of the three categories of exploration expenditures, the average time lag is 4½ years for oil and 5½ years for gas.

b. Time lag for onshore expenditures

A survey of the time lag for predominantly onshore expenditures was presented in connection with FPC proceedings.[1] That survey covered 80 fields,[2] reflecting data from 24 companies, including a majority of the large producers. The survey focused on fields from which deliveries of gas were first made in 1960. As the data were collected by means of a specially designed questionnaire, the results reflect more refined techniques of measurement (including the use of discount factors in the weighting of expenditures) than those employed in the analysis of offshore data.

The major drawbacks of the onshore survey are that it relates only to gas fields and that data are not available separately for South Louisiana. However, there is no apparent reason why the time lag in onshore Louisiana should be different from other onshore areas. In the absence of any data for time lag on oil fields, an adjustment will be made to the gas survey data in order to obtain an approximation for the typical time lag in oil fields. That adjustment will take the form of deducting one year's time lag from the time lag computed for the different cost items for gas. The estimate of a lesser time lag of one year is based on the delays arising from the need to commit relatively large volumes of gas before a pipeline is induced to construct a line and the need to obtain FPC approval before commencing deliveries.

A summary of the results of the time lag study for onshore, compared to the previously discussed time lag results for offshore operations, is shown below:

Years of Preproduction Time Lag

	Gulf of Mexico			Onshore		
	Oil Reservoirs	Gas Reservoirs	Total Hydrocarbons	Oil Reservoirs	Gas Reservoirs	Total Hydrocarbons[a]
Drilling & equipping wells	0.75	2.0	1.2		1.0	0.5
Dry holes	1.5	1.5	1.5		1.0	0.4
Lease acquisitions	3.0	4.0	3.5	2.4	3.4	3.0
Other exploratory costs	4.5	5.5	4.9	2.5	3.5	3.0

a/ The time lag for the total hydrocarbons reflects an average of the time lag for oil and gas, weighted by expenditures. The figures shown in the table reflect the weighted average of onshore South Louisiana; the weighted average for the "Other U.S." is 0.3 for drilling, equipping wells and dry holes, and 2.8 for lease acquisitions and other exploratory costs.

The above table shows that for every item the time lag is greater for offshore (Gulf of Mexico) than for onshore operations.

[1] The study was presented by Warren B. Davis, Director of the Planning and Economics Department, Gulf Oil Corporation; see AR64-1 and AR64-2 and Exh. 39-J, Sch. 4

[2] Including two offshore fields.

XIV. Depletion Rates of Oil and Gas Reservoirs

The use of the discounted cash flow technique for the computation of the return earned on finding cost outlays requires the development of production or depletion curves for the major hydrocarbon products: crude oil, condensate and gas. The discounted cash flow results computed in this study are highly sensitive to changes in the depletion pattern of the reservoirs. The estimation of an industry-wide cost for different areas calls for the construction of average reservoir depletion rates, a necessary theoretical abstraction in view of the widely varying depletion rates of individual fields or reservoirs. The depletion rates used in this study are shown on page 227.

In general, the construction of production curves was based on the historical depletion patterns of the different types of hydrocarbons and the operational and technical factors which are constraints on producing rates. The levels of production rates and the indicated total life of oil and gas fields were tested against the actual producing history of major fields. Production rates were also compared with maximum production rates permitted either by conservation agencies (oil) or contractual arrangements (gas).

Non-associated gas reservoirs: Depletion rates for non-associated gas fields were found to be the same in the *Gulf of Mexico* as *onshore South Louisiana.* The depletion rates were developed from a consideration of reserve additions during the period 1954-1967, average annual production per well, and the decline trend exhibited by a limited number of fields. Lag in the buildup of production from first production to full-rate production was determined by examination of the history of approximately 140 major fields. The trend toward more rapid production buildup in recent years, as more extensive marketing facilities have become available, is reflected in the depletion curves. The results obtained by the above procedure were compared with prevailing rates of take under gas purchase contract provisions.

The depletion rates for non-associated gas fields for the *U.S. excluding South Louisiana* were developed from a national depletion curve presented in FPC proceedings,[1] with appropriate adjustments for the more rapid depletion rates found in South Louisiana. The propriety of the national depletion curve may be judged by a comparison between the implicit reserves-production (R:P) ratio of the curve and the existing national R:P ratio. The implicit R:P ratio of the national curve was 15.4 years, or very close to the end of 1967 R:P ratio of about 16 years.

The depletion rates for condensate—which are faster than for gas—were developed on the basis of an analysis of gas-condensate ratios in more than 100 fields. The influence of producing mechanism (both water drive and pressure depletion) on gas-condensate ratios was also taken into account.

Crude oil reservoirs: Offshore Gulf of Mexico oil reservoirs are depleted relatively faster than onshore South Louisiana reservoirs, and the latter are depleted faster than reservoirs in the remaining U.S. The production curves were developed on the basis of average annual reserve additions per well (1954-1967), annual production per well, and decline trends exhibited by selected fields. The buildup in production rates to full rate production for Gulf of Mexico and onshore South Louisiana was based on production histories of approximately 160 fields. No production buildup was included in the curve for the U.S. excluding South Louisiana, for the reason that most wells are able to market oil almost immediately after completion.

The depletion rate for associated gas reserves was assumed to be the same as for crude oil reservoirs, although in the case of solution gas drive reservoirs the crude oil depletion rate is faster in the earlier and slower in the later part of the life of the reservoirs than the depletion rate for dissolved gas.

Conclusions

The conclusions to this study will be found in the "Summary of Findings" preceding Chapter A.

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[1] Study presented by Warren B. Davis, *op. cit.*

EXHIBITS

Table 1
SUMMARY OF ESTIMATED REVENUES
AND COSTS OF FINDING AND PRODUCING HYDROCARBONS[1/]

	Gulf of Mexico	Onshore So. La.	U.S. Excluding Gulf of Mexico and Onshore So. La.
	(Dollars per barrel)		
Finding Costs			
Successful well drilling costs	.45	.47	.42
Lease facilities	.08	.10	.13
Dry holes	.24	.28	.22
Lease acquisitions	.27	.12	.13
Geophysical, geological, lease rentals, land, scouting, and other exploratory expenses	.15	.20	.17
Total Finding Costs	1.19	1.17	1.07
Other Costs			
Production operating expenses	.35	.41	.47
Transportation of crude oil and lease condensate	.08		
Production taxes		.25	.13
Overhead expenses	.16	.18	.17
Total Other Costs	.59	.84	.77
Revenues and Royalties			
Gross revenues	3.38	3.58	2.95
Royalties	.56	.54	.38
Net Revenues	2.82	3.04	2.57

[1/] Non-associated gas converted to equivalent barrels of oil on a revenue basis.

Table 2

SUMMARY OF ESTIMATED REVENUES AND COSTS OF FINDING AND PRODUCING OIL AND GAS[1]

Gulf of Mexico

	Crude Oil Reservoirs ($/bbl.)	Non-Associated Gas Reservoirs (¢ /Mcf)	Total Hydrocarbons ($/bbl.)
Finding Costs			
Successful well drilling costs	.51 - .53	2.81 - 2.45	.45
Lease facilities	.10	.53 - .47	.08
Dry holes	.28	1.30	.24
Lease acquisitions	.25 - .28	2.21 - 1.82	.27
Geophysical, geological, lease rentals, land, scouting, and other exploratory expenses	.16	1.00	.15
Total Finding Costs	1.30 - 1.35	7.85 - 7.04	1.19
Other Costs			
Production operating expenses	.33	2.75	.35
Transportation of crude oil and lease condensate	.12	.23	.08
Production taxes		.03	
Overhead expenses	.18	1.06	.16
Total Other Costs	.63	4.07	.59
Revenues and Royalties			
Gross revenues	3.38	24.86	3.38
Royalties (16.67%)	.56	4.14	.56
Net Revenues	2.82	20.72	2.82

1/ Non-associated gas converted to equivalent barrels of oil on a revenue basis.

Table 3

SUMMARY OF ESTIMATED REVENUES
AND COSTS OF FINDING AND PRODUCING OIL AND GAS [1]
Onshore South Louisiana

	Crude Oil Reservoirs ($/bbl.)	Non-Associated Gas Reservoirs (¢/Mcf)	Total Hydrocarbons ($/bbl.)
Finding Costs			
Successful well drilling costs	.49	3.55	.47
Lease facilities	.10	.75	.10
Dry holes	.29	2.07	.28
Lease acquisitions	.10	1.15	.12
Geophysical, geological, lease rentals, land, scouting, and other exploratory expenses	.21	1.58	.20
Total Finding Costs	1.19	9.10	1.17
Other Costs			
Production operating expenses	.51	2.34	.41
Production taxes	.21	2.34	.25
Overhead expenses	.19	1.38	.18
Total Other Costs	.91	6.06	.84
Revenues and Royalties			
Gross revenues	3.58	28.56	3.58
Royalties (15%)	.54	4.28	.54
Net Revenues	3.04	24.28	3.04

[1] Non-associated gas converted to equivalent barrels of oil on a revenue basis.

Table 4

SUMMARY OF ESTIMATED REVENUES
AND COSTS OF FINDING AND PRODUCING OIL AND GAS[1/]
Continental United States Excluding
Gulf of Mexico and Onshore South Louisiana

	Crude Oil Reservoirs ($/bbl.)	Non-Associated Gas Reservoirs (¢/Mcf)	Total Hydrocarbons ($/bbl.)
Finding Costs			
Successful well drilling costs	.39	3.64	.42
Lease facilities	.14	.80	.13
Dry holes	.21	1.92	.22
Lease acquisitions	.11	1.26	.13
Geophysical, geological, lease rentals, land, scouting, and other exploratory expenses	.16	1.34	.17
Total Finding Costs	1.01	8.96	1.07
Other Costs			
Production operating expenses	.55	1.74	.47
Production taxes	.12	1.13	.13
Overhead expenses	.17	1.18	.17
Total Other Costs	.84	4.05	.77
Revenues and Royalties			
Gross revenues	2.95	20.65	2.95
Royalties (13%)	.38	2.68	.38
Net Revenues	2.57	17.97	2.57

1/ Non-associated gas converted to equivalent barrels of oil on a revenue basis.

Table 5
ESTIMATED GROSS ANNUAL RESERVE ADDITIONS
OF CRUDE OIL AND NATURAL GAS

	Crude Oil			Non-Associated Gas			Associated Gas			Total Natural Gas		
	Offshore Louisiana	Onshore So. La.	Other Continental U. S.	Offshore Louisiana	Onshore So. La.	Other Continental U. S.	Offshore Louisiana	Onshore So. La.	Other Continental U. S.	Offshore Louisiana	Onshore So. La.	Other Continental U. S.
	(Thousand Barrels)			(Billions of Cubic Feet at 14.73 psia)								
Thru 1947	10,000	2,640,566	53,856,175		13,540	151,586	15	5,352	92,287	15	18,892	243,873
1948	10,000	199,063	3,586,144	208	583	6,653	14	470	5,895	222	1,053	12,548
1949	12,822	185,606	2,989,417	1,120	1,304	4,385	17	820	4,960	1,137	2,124	9,345
1950	36,502	324,818	2,201,365	28	1,651	7,337	50	393	2,526	78	2,044	9,863
1951	29,135	290,999	4,093,820	400	1,118	6,906	40	69	7,433	440	1,187	14,339
1952	53,948	381,907	2,313,433	457	2,173	6,939	74	756	3,869	531	2,929	10,808
1953	35,016	373,278	2,887,836	140	2,513	12,632	48	714	4,295	188	3,227	16,927
1954	108,407	288,641	2,475,989	58	2,560	2,983	149	376	3,421	207	2,936	6,404
1955	256,991	259,229	2,354,504	1,736	3,599	7,343	353	1,047	7,820	2,089	4,646	15,163
1956	288,937	289,338	2,396,061	1,058	1,872	12,292	397	1,021	8,076	1,455	2,893	20,368
1957	213,927	241,605	1,969,268	1,852	4,566	9,701	293	1,190	2,406	2,145	5,756	12,107
1958	157,940	275,907	2,174,395	1,166	3,529	12,600	217	310	1,075	1,383	3,839	13,675
1959	263,633	630,409	2,768,702	2,000	3,656	9,346	362	1,174	4,083	2,362	4,830	13,429
1960	185,105	252,287	1,903,936	3,101	1,636	6,712	254	1,237	904	3,355	2,873	7,616
1961	292,101	169,034	2,132,416	1,409	3,736	9,162	401	-131	1,773	1,810	3,605	10,935
1962	229,364	323,304	1,618,228	4,252	4,075	8,926	315	530	670	4,567	4,605	9,596
1963	248,306	162,581	1,762,213	3,282	2,159	7,834	341	1,444	3,044	3,623	3,603	10,878
1964	389,419	111,610	2,144,738	3,142	3,116	10,985	534	164	2,164	3,676	3,280	13,149
1965	261,565	267,713	2,430,801	2,728	4,611	10,955	359	104	2,401	3,087	4,715	13,356
1966	382,312	332,092	2,073,574	2,447	1,520	12,169	525	1,017	1,568	2,972	2,537	13,737
1967	347,540	353,060	2,173,177	4,010	2,408	10,866	800	964	2,046	4,810	3,372	12,911
Averages:												
1948-1967	190,148	285,624	2,422,501	1,730	2,619	8,836	277	683	3,521	2,007	3,303	12,357
1948-1957	104,569	283,448	2,726,784	706	2,194	7,717	144	686	5,070	849	2,880	12,787
1958-1967	275,728	287,800	2,118,218	2,754	3,045	9,956	411	681	1,973	3,164	3,726	11,929
1961-1967	307,230	245,628	2,047,878	3,039	3,089	10,128	468	585	1,952	3,506	3,674	12,080
1963-1967	325,828	245,411	2,116,900	3,122	2,763	10,562	512	739	2,245	3,634	3,501	12,807

Note: For techniques of estimating annual reserve additions, see text.

TABLE 6

END OF YEAR RESERVES OF NATURAL GAS AND NATURAL GAS LIQUIDS
1946 – 1967

	South Louisiana						Continental U. S. Excluding South Louisiana					
	Non-Associated Reserves			Associated Reserves			Non-Associated Reserves			Associated Reserves		
	Natural Gas (Bcf)	Natural Gas Liquids (Mil. Bbl.)	Liquids Per MMcf of Gas (Bbl.)	Natural Gas (Bcf)	Natural Gas Liquids (Mil. Bbl.)	Liquids Per MMcf of Gas (Bbl.)	Natural Gas (Bcf)	Natural Gas Liquids (Mil. Bbl.)	Liquids Per MMcf of Gas (Bbl.)	Natural Gas (Bcf)	Natural Gas Liquids (Mil. Bbl.)	Liquids Per MMcf of Gas (Bbl.)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1946	12,278	266	21.7	3,302	52	15.7	103,530	1,664	16.1	40,594	1,181	29.1
1947	12,871	288	22.4	4,034	74	18.3	106,230	1,640	15.4	41,890	1,251	29.9
1948	13,167	297	22.1	4,348	78	17.9	109,257	1,726	15.8	45,648	1,440	31.5
1949	15,697	345	22.0	5,004	93	18.6	109,736	1,760	16.0	48,678	1,531	31.5
1950	17,150	382	22.3	5,244	91	17.4	112,769	1,990	17.6	49,082	1,805	36.8
1951	18,184	425	23.4	5,133	94	18.3	114,861	1,979	17.2	54,110	2,227	41.2
1952	20,351	446	21.9	5,733	98	17.1	116,541	1,965	16.9	55,337	2,488	45.0
1953	22,395	486	21.9	6,243	104	16.7	123,658	2,244	18.1	56,820	2,604	45.8
1954	24,306	559	23.0	6,528	113	17.3	120,977	2,089	17.3	57,477	2,483	43.2
1955	28,718	591	20.6	7,660	139	18.1	122,511	2,029	16.6	62,233	2,680	43.1
1956	30.580	646	21.1	8,753	174	19.9	128,584	2,164	16.8	67,073	2,919	43.5
1957	35,759	707	19.8	9,888	188	19.0	131,799	1,999	15.2	66,110	2,793	42.2
1958	39,006	890	22.8	10,042	184	18.3	137,889	2,341	17.0	64,094	2,789	43.5
1959	42,952	1,017	23.7	11,034	229	20.8	140,161	2,401	17.1	65,075	2,875	44.2
1960	45,764	1,086	23.7	11,962	240	20.1	139,432	2,601	18.7	62,889	2,889	45.9
1961	48,871	1,171	24.0	11,499	217	18.9	140,945	2,681	19.0	61,706	2,980	48.3
1962	54,905	1,348	24.6	11,658	240	20.6	142,215	2,890	20.3	59,377	2,834	47.7
1963	57,773	1,481	25.6	12,664	245	19.3	141,820	3,091	21.8	59,459	2,857	48.0
1964	61,213	1,602	26.2	12,667	212	16.7	144,161	3,189	22.1	58,439	2,743	46.9
1965	65,225	1,802	27.6	12,445	249	20.0	146,212	3,238	22.1	57,511	2,735	47.6
1966	65,462	1,829	27.9	13,151	305	23.2	149,220	3,400	22.8	55,328	2,795	50.5
1967	67,573	2,124	31.4	13,851	343	24.8	150,795	3,452	22.9	53,678	2,695	50.2

Source: AGA–API, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas, 1967.

Table 7

IMPLICIT LIQUID YIELDS OF ALTERNATIVE ESTIMATES
OF GROSS ADDITIONS OF NON-ASSOCIATED GAS LIQUIDS,
OFFSHORE AND ONSHORE SOUTH LOUISIANA

1952 - 1966

	Total South Louisiana Gross Reserve Additions			Estimates of Liquid Yields for Offshore and Onshore					
	Non-Associated Natural Gas Liquids	Non-Associated Gas	Liquid Yield of Non-Associated Gas Col. (1) ÷ Col. (2)	Estimate Number 1		Estimate Number 2		Estimate Number 3	
				Offshore	Onshore	Offshore	Onshore	Offshore	Onshore
	(000 bbls.)	(Bcf)	(bbls. per MMcf)	Barrels Per M M c f					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Thru 1951	494,478	19,952	24.78	19.98	25.24	-70.10	33.94	13.94	25.83
1952	39,839	2,630	15.15	19.98	14.13	-74.21	33.94	4.32	17.43
1953	57,530	2,653	21.68	19.98	21.78	-198.29	33.94	20.34	21.76
1954	94,579	2,618	36.13	19.98	36.49	132.64	33.94	80.72	35.12
1955	59,107	5,335	11.08	19.98	6.79	-36.32	33.94	3.37	14.80
1956	83,277	2,930	28.42	19.98	33.19	18 66	33.94	7.79	40.08
1957	94,834	6,418	14.78	19.98	12.67	-32.47	33.94	7.60	17.69
1958	223,762	4,695	47.66	19.98	56.81	89.18	33.94	28.50	53.99
1959	171,682	5,656	30.35	19.98	36.03	23.80	33.94	12.75	39.99
1960	127,203	4,737	26.85	19.98	39.88	23.11	33.94	6.09	66.21
1961	154,252	5,145	29.98	19.98	33.75	19.48	33.94	16.26	35.16
1962	256,952	8,327	30.86	19.98	42.21	27.90	33.94	17.95	44.33
1963	221,651	5,441	40.74	19.98	72.29	45.21	33.94	23.40	67.09
1964	223,974	6,258	35.79	19.98	51.73	37.62	33.94	28.23	43.41
1965	309,867	7,339	42.22	19.98	55.38	56.22	33.94	50.61	37.26
1966	153,933	3,967	38.80	19.98	69.11	41.82	33.94	28.03	56.15
Cumulative Thru 1966	2,766,920	94,101	29.40	19.98	33.94	19.98	33.94	19.98	33.94

The liquid yield of non-associated gas reserve additions through 1966 was derived as follows:

Gross Additions Thru 1966	Offshore	Onshore	Total South Louisiana
Non-associated natural gas liquids (000 bbls.)	611,148	2,155,772	2,766,920
Non-associated natural gas (Bcf)	30,584	63,517	94,101
Liquid-gas ratios (bbls/MMcf)	19.98	33.94	29.40

Estimate Number 1: Assuming constant yield for offshore (as per above), and onshore computed by deducting offshore from total estimates shown in Column (1).

Estimate Number 2: Assuming constant yield for onshore (as per above), and offshore computed by deducting onshore from total estimates shown in Column (1).

Estimate Number 3: Distribution between onshore and offshore non-associated natural gas liquid reserve additions based on increments of production of non-associated natural gas liquids, lagged one year for onshore and three years for offshore. The annual percentage distribution of the lagged increments reflected an increasing proportion attributable to offshore. The computed percentages were adjusted, resulting in the following proportions of total South Louisiana gross additions of non-associated natural gas liquids attributed to offshore: Through 1954 - 5%; 1955-1956 - 10%; 1957-1961 - 15%; 1962 - 30%; 1963 - 35%; 1964 - 40%; 1965-1966 - 45%. The total of the annual estimates for offshore gross additions thus derived was one percent above the cumulative total of 611,148,000 barrels and the annual estimates were adjusted downward proportionately.

Source: Table 5 and text.

Table 8
NUMBER OF WELLS AND FOOTAGE DRILLED
Offshore Louisiana
1954 – 1967

Year	Number of Wells			Footage (000 Feet)		
	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes
1954	121	16	43	1,109	169	430
1955	272	33	64	2,534	362	655
1956	253	58	137	2,290	638	1,386
1957	345	75	146	3,064	833	1,462
1958	292	61	99	2,697	680	993
1959	277	70	114	2,663	827	1,257
1960	271	85	156	2,559	993	1,706
1961	274	101	138	2,734	1,158	1,468
1962	279	111	223	2,831	1,244	2,319
1963	298	84	290	3,054	1,047	3,105
1964	396	80	304	3,979	964	3,261
1965	485	124	289	4,899	1,515	3,085
1966	437	133	371	4,446	1,523	3,982
1967	396	146	399	4,248	1,688	4,170
Averages:						
1954-67	314	84	198	3,079	974	2,091
1958-67	340	100	238	3,411	1,164	2,535
1961-67	366	111	288	3,742	1,306	3,056
1963-67	402	113	331	4,125	1,347	3,520

Source: Number of Wells - Louisiana Geological Survey, annual reported completions adjusted to exclude multiple completions.

Footage - Average depth per well, computed from World Oil drilling reports, multiplied by number of wells.

Table 9

NUMBER OF WELLS AND FOOTAGE DRILLED
Onshore South Louisiana
1954 - 1967

	Number of Wells			Footage (000 Feet)		
Year	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes
1954	712	271	539	6,747	3,079	5,395
1955	815	279	676	7,850	3,291	6,918
1956	702	293	707	6,656	3,510	7,431
1957	711	307	755	7,594	3,715	7,913
1958	709	308	700	6,795	3,758	7,568
1959	728	367	745	6,840	4,518	8,009
1960	772	302	683	7,349	3,732	7,153
1961	755	288	710	7,126	3,600	7,389
1962	766	235	687	7,420	2,949	7,380
1963	784	220	707	7,430	2,773	7,360
1964	676	263	715	6,125	3,183	7,619
1965	743	227	679	6,293	2,927	7,155
1966	613	190	559	5,575	2,485	5,777
1967	527	195	590	4,555	2,422	6,203
Averages:						
1954-67	715	268	675	6,740	3,282	7,091
1958-67	707	260	678	6,551	3,235	7,161
1961-67	695	231	664	6,360	2,906	6,983
1963-67	669	219	650	5,996	2,758	6,823

Sources: Number of Wells - 1958-1967: Louisiana Geological Survey, annual reported completions adjusted to exclude multiple completions; 1954-1957: World Oil total for South Louisiana minus Offshore Louisiana from Table 8.

Footage - Average depth per well, computed from World Oil drilling reports, multiplied by number of wells.

Table 10
NUMBER OF WELLS AND FOOTAGE DRILLED

Continental United States,
Excluding Onshore and Offshore South Louisiana
1948 - 1967

	Number of Wells			Footage (000 Feet)		
Year	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes
1948	21,796	3,223	11,658	75,203	11,590	39,770
1949	20,898	3,405	12,602	75,158	11,889	41,836
1950	23,157	3,326	14,559	87,202	12,417	48,090
1951	23,024	3,419	17,129	90,620	13,190	60,901
1952	22,861	3,529	17,799	93,279	14,291	67,869
1953	24,491	4,004	18,265	95,062	16,998	70,020
1954	27,230	3,932	18,555	105,577	16,671	70,770
1955	29,387	3,863	19,824	111,721	16,030	78,004
1956	29,686	4,144	21,410	111,465	18,446	81,569
1957	26,463	4,240	19,349	99,921	19,693	74,032
1958	23,335	4,704	17,606	84,303	21,481	66,264
1959	24,495	4,493	17,784	87,372	21,938	70,203
1960	21,245	4,787	17,376	76,925	23,828	68,543
1961	20,397	5,168	16,460	75,618	25,402	65,659
1962	20,652	5,019	15,935	77,863	24,906	65,106
1963	19,046	4,295	15,682	71,229	21,102	64,988
1964	18,829	4,397	16,596	70,323	22,032	69,661
1965	16,905	4,223	15,089	62,780	21,683	64,614
1966	15,125	4,079	13,970	57,071	22,583	59,526
1967	14,131	3,339	11,815	50,787	18,301	51,499
Averages:						
1948 - 67	22,158	4,079	16,473	82,974	18,724	63,946
1948 - 57	24,899	4,179	17,115	94,521	15,122	63,286
1958 - 67	19,416	4,450	15,831	71,427	22,326	64,606
1961 - 67	17,869	4,360	15,078	66,524	22,287	63,008
1963 - 67	16,807	4,067	14,630	62,438	21,140	62,058

Source: World Oil.

Table 11

ESTIMATED GROSS RESERVE ADDITIONS
PER WELL DRILLED

1954 - 1967

Year	Offshore South Louisiana: Crude Oil (000 bbls)	Offshore South Louisiana: Non-Associated Gas (Bcf)	Onshore South Louisiana: Crude Oil (000 bbls)	Onshore South Louisiana: Non-Associated Gas (Bcf)	Continental United States, Excluding South Louisiana: Crude Oil (000 bbls)	Continental United States, Excluding South Louisiana: Non-Associated Gas (Bcf)
1954	896	3.6	405	9.4	91	0.8
1955	945	52.6	318	12.9	80	1.9
1956	1,142	18.2	412	6.4	81	3.0
1957	620	24.7	340	14.9	74	2.3
1958	541	19.1	389	11.5	93	2.7
1959	952	28.6	866	10.0	113	2.1
1960	683	36.5	327	5.4	90	1.4
1961	1,066	14.0	224	13.0	105	1.8
1962	822	38.3	422	17.3	78	1.8
1963	833	39.1	207	9.8	93	1.8
1964	983	39.3	165	11.8	114	2.5
1965	539	22.0	360	20.3	144	2.6
1966	875	18.4	542	8.0	137	3.0
1967	878	27.5	670	12.3	154	3.3
Averages:						
1954-67	825	27.4	395	11.5	103	2.2
1958-67	811	27.5	407	11.7	109	2.2
1961-67	839	27.4	353	13.4	115	2.3
1963-67	811	27.6	367	12.6	126	2.6

Source: Table 5, page 209; Table 8, page 212; Table 9, page 213 and Table 10, page 214.

Table 12

ESTIMATED GROSS RESERVE ADDITIONS PER FOOT DRILLED

1954 - 1967

Year	Offshore South Louisiana Crude Oil (bbls)	Offshore South Louisiana Non-Associated Gas (Mcf)	Onshore South Louisiana Crude Oil (bbls)	Onshore South Louisiana Non-Associated Gas (Mcf)	Continental United States, Excluding South Louisiana Crude Oil (bbls)	Continental United States, Excluding South Louisiana Non-Associated Gas (Mcf)
1954	98	343	43	831	23	179
1955	101	4,796	33	1,094	21	458
1956	126	1,658	43	533	21	666
1957	70	2,223	32	1,229	20	493
1958	59	1,715	41	939	26	587
1959	99	2,418	92	809	32	426
1960	72	3,123	34	438	25	282
1961	107	1,217	24	1,038	28	361
1962	81	3,418	44	1,382	21	358
1963	81	3,135	22	779	25	371
1964	98	3,259	18	979	30	499
1965	53	1,801	43	1,575	39	505
1966	86	1,607	60	612	36	539
1967	82	2,376	78	994	43	594
Averages:						
1954-67	84	2,364	42	937	28	448
1958-67	81	2,366	44	941	30	446
1961-67	82	2,327	39	1,063	31	454
1963-67	79	2,318	41	1,002	34	500

Source: Table 5, page 209; Table 8, page 212; Table 9, page 213 and Table 10, page 214.

Table 13

WELL DRILLING AND EQUIPPING COST PER FOOT

1959 - 1967

Year	Offshore South Louisiana				Onshore South Louisiana				Continental United States Excluding South Louisiana			
	Oil Wells	Gas Wells	Total Productive Wells	Dry Holes	Oil Wells	Gas Wells	Total Productive Wells	Dry Holes	Oil Wells	Gas Wells	Total Productive Wells	Dry Holes
	(Dollars Per Foot)											
1959	34.08	53.76	39.25	35.22	22.56	28.36	24.51	17.39	12.20	51.32	12.85	8.70
1960	34.33	50.53	38.57	32.52	19.56	28.12	22.35	18.30	11.74	15.76	12.74	9.14
1961	35.49	47.51	40.41	33.58	18.88	29.30	22.10	17.26	11.56	15.13	12.51	9.09
1962	35.02	43.11	42.05	29.62	19.08	30.25	22.40	17.33	11.92	15.35	12.82	9.22
1963	34.37	45.17	42.87	31.85	17.65	26.21	19.95	14.76	11.70	14.83	12.45	8.76
1964	35.86	40.15	39.32	31.33	18.18	27.90	21.36	16.42	11.26	15.59	12.33	8.76
1965	39.38	51.58	41.64	33.88	18.19	28.30	20.93	16.94	11.47	15.48	12.51	9.08
1966	41.23	55.09	44.77	36.93	19.16	34.45	24.12	17.96	12.06	17.30	13.49	9.53
1967 1/	42.47	56.74	46.11	38.04	19.73	35.48	24.84	18.50	12.42	17.82	13.89	9.82

1/ Estimated.

Source: Joint Association Survey of Industry Drilling Costs.

Table 14
ESTIMATES OF GROSS INVESTMENT IN LEASE FACILITIES
IN RELATION TO PRODUCTIVE DRILLING INVESTMENTS
Year-End 1962
(Millions of Dollars)

Gross Investment	United States: Oil & Oil Casinghead Leases	United States: Gas & Gas Condensate Leases	United States: Combination Leases	United States: Total, All Leases	South Louisiana: Oil & Oil Casinghead Leases	South Louisiana: Gas & Gas Condensate Leases	South Louisiana: Combination Leases	South Louisiana: Total, All Leases	Other United States: Oil & Oil Casinghead Leases	Other United States: Gas & Gas Condensate Leases	Other United States: Combination Leases	Other United States: Total, All Leases
1. Lease and well equipment	4,051	1,005	1,070	6,126	370	295	459	1,124	3,681	710	611	5,002
2. Intangible development	5,610	2,021	1,953	9,584	689	575	936	2,200	4,921	1,446	1,017	7,384
3. Total	9,661	3,026	3,023	15,710	1,059	870	1,395	3,324	8,602	2,156	1,628	12,386
4. Intangible development cost as percent of total drilling costs	70.7%a/	74.5%a/	71.5%a/	71.6%b/	71.6%a/	74.1%a/	73.1%a/	72.9%b/	70.6%b/	74.7%b/	70.1%b/	71.3%b/
5. Estimated total successful well drilling and equipping investment (Line 2 ÷ Line 5)	7,935	2,713	2,731	13,379	962	776	1,280	3,018	6,973	1,937	1,451	10,361
6. Estimated lease equipment (Line 3 - Line 5)	1,726	313	292	2,331	97	94	115	306	1,629	219	177	2,025
7. Related producing facilities	349	150	135	634	67	43	64	174	282	107	71	460
8. Total lease equipment and related producing facilities (Line 6 + Line 7)	2,075	463	427	2,965	164	137	179	480	1,911	326	248	2,485
9. Ratio of lease equipment and related producing facilities to successful well drilling investment (Line 8 ÷ Line 5)	26.1%	17.1%	15.6%	22.2%	17.0%	17.7%	14.0%	15.9%	27.4%	16.8%	17.1%	24.0%
10. Lease equipment investment needed for oil leases in relation to gas leases		$\frac{26.1}{17.1} = 1.53$				$\frac{17.0}{17.7} = 0.96$				$\frac{27.4}{16.8} = 1.63$		

a/ Derived from 1955-1962 drilling cost data as reported in "All Areas Questionnaire".
b/ Line 2 ÷ Line 5.

Source: Data derived from responses to "All Areas Questionnaire", Schedule D, sent out by FPC in connection with Docket Nos. AR64-1 and AR64-2.

Table 15

RATIOS OF DRY HOLES TO PRODUCTIVE WELLS DRILLED

1958 - 1967

	Wildcat Wells		Field Wells		Total Wells		
	World Oil	Oil & Gas Journal	World Oil	Oil & Gas Journal	World Oil	Oil & Gas Journal	Louisiana Geological Survey
Offshore Louisiana							
1958	4.71	2.38	0.23	0.33	0.32	0.38	0.28
1959	2.60	4.00	0.29	0.37	0.36	0.41	0.33
1960	11.33	5.80	0.37	0.32	0.46	0.40	0.44
1961	41.00	16.33	0.31	0.30	0.43	0.43	0.38
1962		2.66	0.50	0.50	0.76	0.69	0.57
1963	18.78	7.09	0.36	0.42	0.77	0.80	0.76
1964	29.60	6.95	0.49	0.47	0.80	0.75	0.64
1965	18.14	9.08	0.60	0.56	0.85	0.80	0.47
1966	35.80	N.A.	0.78	N.A.	1.17	N.A.	0.65
1967	24.00	N.A.	0.74	N.A.	1.07	N.A.	0.74
Averages:							
1958-62	11.52	3.68	0.35	0.37	0.48	0.48	0.40
1963-65	21.14	7.50	0.49	0.49	0.81	0.78	0.60
1963-67	23.97		0.60		0.93		0.64
1958-65	16.33	5.58	0.41	0.42	0.62	0.61	0.49
1958-67	19.13		0.49		0.73		0.54
Onshore South Louisiana							
1958	7.95	6.68	0.44	0.48	0.75	0.69	0.69
1959	10.56	8.41	0.47	0.43	0.71	0.62	0.68
1960	6.16	7.33	0.45	0.41	0.66	0.60	0.64
1961	11.52	7.35	0.48	0.48	0.72	0.71	0.68
1962	28.56	6.02	0.56	0.54	0.82	0.76	0.69
1963	13.33	8.98	0.62	0.54	0.80	0.81	0.70
1964	10.90	6.20	0.55	0.55	0.79	0.77	0.76
1965	13.12	9.43	0.55	0.50	0.79	0.72	0.70
1966	12.33	N.A.	0.56	N.A.	0.77	N.A.	0.70
1967	30.80	N.A.	0.64	N.A.	0.86	N.A.	0.82
Averages:							
1958-62	9.95	7.05	0.49	0.47	0.73	0.67	0.67
1963-65	12.38	7.99	0.55	0.53	0.79	0.77	0.72
1963-67	13.60		0.57		0.80		0.73
1958-65	10.67	7.37	0.51	0.49	0.75	0.71	0.69
1958-67	11.28		0.53		0.76		0.70
Continental United States, Excluding Offshore and Onshore South Louisiana							
1958	9.40	6.10	0.34	0.38	0.63	0.65	
1959	8.19	6.57	0.33	0.35	0.61	0.63	
1960	9.43	6.39	0.37	0.37	0.67	0.67	
1961	9.22	5.98	0.37	0.36	0.64	0.64	
1962	9.17	5.29	0.37	0.35	0.62	0.61	
1963	9.36	5.79	0.40	0.37	0.67	0.64	
1964	9.38	5.39	0.43	0.40	0.71	0.68	
1965	10.90	6.37	0.42	0.39	0.71	0.68	
1966	8.99	N.A.	0.43	N.A.	0.73	N.A.	
1967	8.76	N.A.	0.40	N.A.	0.68	N.A.	
Averages:							
1958-62	8.82	6.06	0.36	0.36	0.63	0.64	
1963-65	9.82	5.81	0.41	0.38	0.70	0.67	
1963-67	9.47		0.42		0.70		
1958-65	9.14	5.97	0.38	0.37	0.66	0.65	
1958-67	9.10		0.38		0.66		

Table 16

NUMBER OF WILDCAT AND FIELD WELLS DRILLED

1958-1967

	World Oil						Oil and Gas Journal					
	Wildcat Wells			Field Wells			Wildcat Wells			Field Wells		
	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes	Oil Wells	Gas Wells	Dry Holes
Offshore Louisiana												
1958	3	4	33	308	54	85	3	5	19	235	59	97
1959	2	8	26	286	53	99	1	2	12	215	72	106
1960	0	3	34	271	71	126	0	5	29	265	79	111
1961	0	1	41	277	68	108	0	3	49	285	78	108
1962	0	0	108	318	94	205	10	28	101	297	82	188
1963	3	6	169	322	73	142	10	12	156	302	59	151
1964	2	3	148	391	80	233	11	10	146	382	80	218
1965	4	3	127	425	54	286	9	4	118	412	52	262
1966	1	4	179	394	55	351	Not Available					
1967	4	3	168	389	77	350	Not Available					
Onshore South Louisiana												
1958	14	24	302	651	243	395	11	23	227	731	251	470
1959	10	15	264	735	298	489	12	15	227	806	304	479
1960	16	21	228	713	264	441	14	16	220	785	285	437
1961	8	13	242	728	232	462	12	22	250	723	229	454
1962	3	6	257	746	230	548	16	26	253	787	232	554
1963	7	11	240	751	180	515	16	4	269	735	190	503
1964	8	12	218	673	199	483	15	20	217	648	200	465
1965	8	9	223	713	183	495	8	15	217	745	172	457
1966	5	10	185	676	169	477	Not Available					
1967	2	3	154	514	166	435	Not Available					
Continental United States, excluding offshore and onshore South Louisiana												
1958	726	272	8,384	22,609	4,432	9,222	906	403	7,987	22,692	4,062	10,239
1959	700	347	8,532	23,795	4,146	9,252	859	435	8,501	23,902	4,198	9,931
1960	547	297	7,959	20,698	4,490	9,417	838	426	8,079	19,272	4,444	8,691
1961	509	276	7,240	19,888	4,892	9,220	803	464	7,572	19,252	4,863	8,656
1962	481	254	6,737	20,171	4,765	9,198	824	535	7,183	19,309	4,940	8,374
1963	487	221	6,626	18,559	4,074	9,056	787	409	6,922	18,430	4,062	8,334
1964	522	226	7,017	18,307	4,171	9,579	923	459	7,442	18,637	4,084	8,985
1965	410	188	6,520	16,495	4,035	8,569	690	379	6,811	16,886	4,089	8,147
1966	424	236	5,933	14,701	3,843	8,037	Not Available					
1967	414	166	5,083	13,717	3,173	6,732	Not Available					

Table 17

PROPORTION OF GAS WELL AND OIL WELL DRILLING COSTS
Continental United States (Excluding Alaska)

	Gas Wells	Oil Wells	Total Productive Wells	Total Gas Wells	Total Oil Wells
	(Thousands of Dollars)			(Percent)	
Offshore Louisiana					
1959	44,485	90,748	135,233	32.9	67.1
1960	50,175	87,834	138,009	36.4	63.6
1961	55,039	97,029	152,068	36.2	63.8
1962	53,642	99,132	152,774	35.1	64.9
1963	47,296	104,973	152,269	31.1	68.9
1964	38,717	142,701	181,418	21.3	78.7
1965	78,120	192,941	271,061	28.8	71.2
1966	83,879	183,292	267,171	31.4	68.6
1967	95,805	180,408	276,213	34.7	65.3
Onshore So. Louisiana					
1959	128,124	154,300	282,424	45.4	54.6
1960	104,947	143,755	248,702	42.2	57.8
1961	105,472	134,533	240,005	43.9	56.1
1962	89,193	141,578	230,771	38.7	61.3
1963	72,689	131,139	203,828	35.7	64.3
1964	88,801	111,357	200,158	44.4	55.6
1965	82,826	114,473	197,299	42.0	58.0
1966	85,622	106,822	192,444	44.5	55.5
1967	85,922	89,867	175,789	48.9	51.1
Other Continental United States					
1959	336,090	1,065,938	1,402,028	24.0	76.0
1960	375,529	903,100	1,278,629	29.4	70.6
1961	384,332	874,144	1,258,476	30.5	69.5
1962	382,307	928,127	1,310,434	29.2	70.8
1963	312,943	833,379	1,146,322	27.3	72.7
1964	343,479	791,837	1,135,316	30.3	69.7
1965	335,653	720,087	1,055,740	31.8	68.2
1966	390,686	688,276	1,078,962	36.2	63.8
1967	326,124	630,775	956,899	34.1	65.9

Source: Footage as shown in Table 8, page 212; 9, page 213 and 10, page 214 multiplied by cost per foot derived from Joint Association Survey data (1967 estimated).

Table 18

RELATIONSHIP OF GROSS LEASEHOLD INVESTMENT TO GROSS INVESTMENT IN DRILLING AND EQUIPPING WELLS

South Louisiana and United States

Year - End 1962

	South Louisiana				United States, Excluding South Louisiana			
Gross Investment	Oil & Oil Casinghead Leases	Gas Leases	Combination Leases	Total	Oil & Oil Casinghead Leases	Gas Leases	Combination Leases	Total
	(Millions of Dollars)							
Excluding Pipeline Companies								
1. Lease and well equipment	368	274	453	1,095	3,592	568	734	4,894
2. Intangible development	686	551	924	2,161	4,529	980	1,018	6.527
3. Total (Line 1 + Line 2)	1,054	825	1,377	3,256	8,121	1,548	1,752	11,421
4. Leaseholds	184	252	145	581	1,669	413	247	2,329
5. Leaseholds as a percent of drilling and equipping investment (Line 4 ÷ Line 3)	17.5%	30.5%	10.5%	17.8%	20.6%	26.7%	14.1%	20.4%
Including Pipeline Companies								
6. Lease and well equipment	370	295	459	1,124	3,604	631	733	4,968
7. Intangible development	689	575	936	2,200	4,543	1,164	1,016	6,723
8. Total (Line 6 + Line 7)	1,059	870	1,395	3,324	8,147	1,795	1,749	11,691
9. Leaseholds	185	452	147	784	1,676	473	246	2,395
10. Leaseholds as a percent of drilling and equipping investment (Line 9 ÷ Line 8)	17.5%	52.0%	10.5%	23.6%	20.6%	26.4%	14.1%	20.5%

Source: Data derived from responses to "All Areas Questionnaire", Schedule D, sent out by FPC in connection with Docket Nos. AR64-1 and AR64-2.

Table 19
CREW MONTHS OF GEOPHYSICAL ACTIVITY

1944 - 1966

Year	Offshore Gulf Coast			Other Offshore	Onshore Louisiana[1]			Total U.S., Excluding Louisiana and Offshore Gulf Coast		
	Seismic	Grav. & Mag.	Total	Total	Seismic	Grav. & Mag.	Total	Seismic	Grav. & Mag.	Total
1944	22		22	None or Not Available	Data Not Collected					
1945	31		31							
1946	113	54	167							
1947	427	70	497							
1948	412	46	458							
1949	210	30	240							
1950	82	11	93							
1951	85	9	94							
1952	121	22	143		993	137	1,130	6,844	806	7,650
1953	247	42	289		1,116	142	1,258	6,303	765	7,068
1954	348	60	408		952	135	1,087	5,563	802	6,365
1955	392	105	497		N.A.	N.A.	1,111	N.A.	N.A.	6,632
1956	302	118	420		1,330	65	1,395	5,181	861	6,042
1957	140	77	217		1,255	84	1,339	4,888	798	5,686
1958	55	31	86		938	94	1,032	4,071	542	4,613
1959	64	36	100		877	44	921	4,156	519	4,675
1960	84	14	98		724	26	750	3,817	542	4,359
1961	119	30	149	34	639	27	666	3,799	410	4,209
1962	90	29	119	56	533		533	3,292	287	3,579
1963	110	21	131	42	475	28	503	3,381	159	3,540
1964	208	28	236	82	552	17	569	3,342	259	3,601
1965	353	17	370	119	684	1	685	3,210	206	3,416
1966	356	35	391	117	569	12	581	2,744	116	2,860
Averages:										
1957-1966	158	32	190		725	33	758	3,670	384	4,054
1962-1966	223	26	249	83	562	12	574	3,195	205	3,400

1/ Includes North Louisiana, estimated at 10 percent of total.

N.A. - Not Available.

Source: Annual reports of the Committee on Geophysical Activity of the Society of Exploration Geophysicists.

Table 20

ESTIMATED UNIT REVENUE FROM CRUDE OIL RESERVOIRS

Line No.	Item	Source	Unit	Offshore Louisiana	Onshore South Louisiana	Other Continental U.S.
Crude oil						
1.	Crude oil revenue	Bureau of Mines	$/bbl.	3.13	3.13	2.85
Associated gas						
2.	FPC ceiling prices	FPC Opinions, Examiner decisions & Staff recommendations	¢/Mcf	16.67	18.14	14.42
3.	Compression charge	Estimated	¢/Mcf	.75	.50	1.25
4.	Net revenue	Line 2 - Line 3	¢/Mcf	15.92	17.64	13.17
5.	Gas yield of crude oil	Cumulative gross reserve additions through 1967 for offshore and onshore South Louisiana and 1958-1967 gross additions for Other U. S.	Mcf/bbl.	1.46	2.28	0.93
6.	Revenue per barrel of crude	Line 4 x Line 5	$/bbl.	.23	.40	.12
	Revenue credited to lease					
7.	Percent	FPC records	%	100	100	45
8.	Amount	Line 6 x Line 7	$/bbl.	.23	.40	.05
Associated gas liquids						
9.	Revenue per gallon	Bureau of Mines	¢/gal.	5.75	5.75	5.19
10.	Plant liquid yield of associated gas	Estimated from end of 1967 reserves ratios	GPM	.80	1.20	3.00
11.	Plant liquid yield of crude oil	Line 5 x Line 10	gal./bbl.	1.17	2.74	2.79
12.	Revenue per barrel of crude oil	Line 9 x Line 11	¢/bbl.	6.73	15.76	14.48
13.	Fuel loss & shrinkage	Estimated at [6% of Line 2] x Line 5	¢/bbl.	1.46	2.48	.80
14.	Revenue, net of fuel loss and shrinkage	Line 14 - Line 13	¢/bbl.	5.27	13.28	13.68
15.	Revenue credited to lease	35% of Line 14, based on FPC records	$/bbl.	.02	.05	.05
Total revenue from crude oil reservoirs		Line 1 + Line 8 + Line 15	$/bbl.	3.38	3.58	2.95

Table 21

ESTIMATED UNIT REVENUE FROM NON-ASSOCIATED GAS RESERVOIRS

Line No.	Item	Source	Unit	Offshore Louisiana	Onshore South Louisiana	Other Continental U. S.
Non-associated gas						
1.	FPC ceiling prices	FPC Opinions, Examiner decisions & Staff recommendations	¢/Mcf	18.14	19.61	17.00
Lease and plant condensate						
2.	Revenue per barrel	1967 plant condensate revenue, Bureau of Mines	$/bbl.	3.23	3.23	3.20
3.	Condensate yield of non-associated gas	Table 22 and text	Bbls/MMcf	19	25	7.25
4.	Revenue per Mcf	Line 2 x Line 3	¢/Mcf	6.14	8.08	2.32
Plant liquids, other than condensate						
5.	Revenue per gallon	Bureau of Mines, 1967	¢/gal.	5.75	5.75	5.19
6.	Plant liquid yield of non-associated gas	Table 22 and text	gal./Mcf	.35	.50	.80
7.	Revenue per Mcf	Line 5 x Line 6	¢/Mcf	2.01	2.88	4.15
8.	Fuel loss and shrinkage	Estimated at 2 percent of Line 1	¢/Mcf	.36	.39	.34
9.	Revenue net of fuel loss and shrinkage	Line 7 - Line 8	¢/Mcf	1.65	2.49	3.81
10.	Revenue credited to lease	35 percent of Line 9, based on FPC records	¢/Mcf	.58	.87	1.33
Total revenues from non-associated gas reservoirs		Line 1 + Line 4 + Line 10	¢/Mcf	24.86	28.56	20.65

Table 22

ESTIMATE OF LIQUID YIELD
OF NON-ASSOCIATED GAS PRODUCTION

		Unit	South Louisiana 1966	South Louisiana 1967	Other Continental United States 1966	Other Continental United States 1967
	Natural Gas Liquids Production					
1.	Total non-associated natural gas liquids (AGA-API)	MM bbls.	127.0	144.6	239.3	249.2
2.	Total plant liquids (Bureau of Mines)	"	56.4	71.6	412.2	442.9
3.	Total associated natural gas liquids (AGA-API)	"	14.0	21.7	208.4	229.0
4.	Non-associated plant liquids (Line 2 - Line 3)	"	42.4	49.9	203.8	213.9
5.	Estimated lease condensate (Line 1 - Line 4)	"	84.6	94.7	35.5	35.3
6.	Plant condensate[a/] (Bureau of Mines)	"	8.9	11.0	31.6	32.3
7.	Lease and plant condensate (Line 5 + Line 6)	"	93.5	105.7	67.1	67.6
8.	Other non-associated plant liquids (Line 1 - Line 7)	"	33.5	38.9	172.2	181.6
9.	Line 8 converted to gallons (Line 8 x 42)	MM gals.	1,407	1,634	7,232	7,627
10.	Net production of non-associated gas[b/]	Bcf	3,907	4,452	8,919	9,676
	Liquid Yield of Non-Associated Gas Production					
11.	Lease and plant condensate yield of non-associated gas production (Line 7 ÷ Line 10)	Bbls./MMcf	23.9	23.7	7.5	7.0
12.	Plant liquid yield (other than condensate) of non-associated gas production (Line 9 ÷ Line 10)	Gals./Mcf	0.36	0.37	0.81	0.79

a/ Includes 50 percent of finished gasoline and naptha and "other products".

b/ For the Continental United States, gross production of gas-well gas less estimated repressured volumes from the Bureau of Mines; for South Louisiana, production as reported by the Louisiana Department of Conservation. "Other Continental United States" is Continental United States less South Louisiana.

Table 23
DEPLETION RATES FOR AVERAGE CRUDE OIL AND NON-ASSOCIATED GAS RESERVOIRS

Year	Gulf of Mexico: Crude Oil Reservoirs	Gulf of Mexico: Non-Associated Gas Reservoirs: Gas	Gulf of Mexico: Non-Associated Gas Reservoirs: Condensate	Gulf of Mexico: Non-Associated Gas Reservoirs: Total[a/]	Gulf of Mexico: Total Crude Oil & Non-Associated Gas[b/]	Onshore South Louisiana: Crude Oil Reservoirs	Onshore South Louisiana: Non-Associated Gas Reservoirs: Gas	Onshore South Louisiana: Non-Associated Gas Reservoirs: Condensate	Onshore South Louisiana: Non-Associated Gas Reservoirs: Total[a/]	Onshore South Louisiana: Total Crude Oil & Non-Associated Gas[b/]	U.S., Excluding Gulf of Mexico and Onshore South Louisiana: Crude Oil Reservoirs	U.S., Excluding Gulf of Mexico and Onshore South Louisiana: Non-Associated Gas Reservoirs: Gas	U.S., Excluding Gulf of Mexico and Onshore South Louisiana: Non-Associated Gas Reservoirs: Condensate	U.S., Excluding Gulf of Mexico and Onshore South Louisiana: Non-Associated Gas Reservoirs: Total[a/]	U.S., Excluding Gulf of Mexico and Onshore South Louisiana: Total Crude Oil & Non-Associated Gas[b/]
1	1.90%	1.40%	2.11%	1.57%	1.76%	1.37%	1.40%	2.11%	1.61%	3.08%	4.00%	1.56%	2.11%	1.63%	3.41%
2	6.20	2.30	3.47	2.59	4.62	6.00	2.30	3.47	2.64	4.43	4.00	3.32	4.55	3.46	3.87
3	7.00	3.93	5.93	4.42	5.87	6.00	3.93	5.93	4.52	5.31	4.00	3.95	5.41	4.12	4.03
4	7.00	5.00	7.54	5.62	6.40	6.00	5.00	7.54	5.75	5.88	4.00	4.31	5.95	4.52	4.13
5	7.00	5.00	7.54	5.62	6.40	6.00	5.00	7.54	5.75	5.88	4.00	5.00	6.85	5.21	4.30
6	7.00	5.00	7.54	5.62	6.40	6.00	5.00	7.54	5.75	5.88	4.00	5.00	6.85	5.21	4.30
7	7.00	5.00	6.97	5.49	6.34	6.00	5.00	6.97	5.58	5.81	4.00	5.00	6.85	5.21	4.30
8	7.00	5.00	6.60	5.39	6.30	6.00	5.00	6.60	5.47	5.75	4.00	5.00	6.85	5.21	4.30
9	7.00	5.00	6.22	5.30	6.26	6.00	5.00	6.22	5.36	5.70	4.00	5.00	6.85	5.21	4.30
10	7.00	5.00	5.84	5.21	6.22	6.00	5.00	5.84	5.25	5.65	4.00	5.00	6.45	5.17	4.29
11	7.00	5.00	5.47	5.12	6.18	6.00	5.00	5.47	5.14	5.60	4.00	5.00	5.94	5.11	4.28
12	7.00	5.00	5.09	5.02	6.13	6.00	5.00	5.09	5.03	5.55	4.00	4.98	5.46	5.04	4.26
13	6.90	5.00	4.71	4.93	6.04	5.80	5.00	4.71	4.91	5.39	4.00	4.54	4.61	4.55	4.14
14	5.40	5.00	4.33	4.84	5.15	4.95	5.00	4.33	4.80	4.88	4.00	4.13	3.91	4.10	4.02
15	3.80	5.00	3.96	4.74	4.21	4.20	5.00	3.96	4.69	4.43	4.00	3.79	3.31	3.73	3.93
16	2.65	5.00	3.58	4.65	3.52	3.55	5.00	3.58	4.58	4.03	4.00	3.48	2.78	3.40	3.85
17	1.85	5.00	3.20	4.56	3.03	3.00	5.00	3.20	4.47	3.69	4.00	3.16	2.34	3.07	3.77
18	1.30	4.85	2.74	4.33	2.62	2.57	4.85	2.74	4.23	3.34	4.00	2.89	1.98	2.79	3.70
19		4.00	1.96	3.50	1.53	2.18	4.00	1.96	3.40	2.75	4.00	2.66	1.70	2.55	3.64
20		3.20	1.45	2.77	1.21	1.83	3.20	1.45	2.69	2.23	4.00	2.42	1.42	2.31	3.58
21		2.50	1.04	2.14	0.94	1.55	2.50	1.04	2.07	1.79	3.65	2.18	1.19	2.07	3.26
22		2.00	0.75	1.69	0.74		2.00	0.75	1.63	0.76	3.10	1.96	1.01	1.85	2.79
23		1.60	0.58	1.35	0.59		1.60	0.58	1.30	0.61	2.62	1.81	0.87	1.70	2.39
24		1.26	0.44	1.06	0.46		1.26	0.44	1.02	0.48	2.20	1.66	0.76	1.56	2.04
25		1.00	0.33	0.84	0.37		1.00	0.33	0.80	0.37	1.87	1.50	0.63	1.40	1.75
26		0.80	0.25	0.67	0.29		0.80	0.25	0.64	0.30	1.60	1.39	0.55	1.29	1.52
27		0.64	0.20	0.53	0.23		0.64	0.20	0.51	0.24	1.35	1.28	0.47	1.19	1.31
28		0.52	0.16	0.43	0.19		0.52	0.16	0.41	0.19	1.15	1.16	0.40	1.07	1.13
29											0.98	1.05	0.35	0.97	0.98
30											0.83	0.96	0.30	0.88	0.84
31											0.65	0.87	0.26	0.80	0.69
32												0.80	0.22	0.73	0.18
33												0.73	0.20	0.67	0.17
34												0.67	0.17	0.61	0.15
35												0.62	0.15	0.57	0.14
36												0.58	0.14	0.53	0.13
37												0.56	0.13	0.51	0.13
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

a/ Combined by weighting gas and condensate depletion by estimated net revenue per Mcf (excluding royalties and production taxes) from non-associated gas and condensate.

b/ Combined by weighting crude oil and total non-associated depletion in proportion to estimated new revenues from 1963-1967 reserves added.

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